Supreme Court, U.S.
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No.

In The

Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,

Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

AND RELATED PETITIONS

Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

Volume I, pp. 1a - 407a

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TABLE OF CONTENTS

	Page
Appendix A — Opinion — *United Distribution Companies v. Federal Energy Regulatory Commission*, 88 F.3d 1105 (D.C. Cir. 1996)	1a
Appendix B — *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, "Order No. 636", F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939 (1992) ...	175a
Appendix C — *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol*, "Order No. 636-A," *Order on Reh'g*, F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950 (1992)	408a
Appendix D — *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, "Order No. 636-B", *Order on Reh'g*, 61 F.E.R.C. ¶ 61,272 (1992)	813a
Appendix E — *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, "Order No. 636-C", *Notice of Denial of Reh'g*, 62 F.E.R.C. ¶ 61,007 (1993)	999a

Contents

Page

Appendix F — *United Distribution Companies v. Federal Energy Regulatory Commission*, Order Modifying Opinion (October 29, 1996) 1001a

Appendix G — *United Distribution Companies v. Federal Energy Regulatory Commission*, Order Denying Petitions for Rehearing (October 29, 1996) 1003a

Appendix H — *United Distribution Companies v. Federal Energy Regulatory Commission*, Order Denying Suggestions for Rehearing *In Banc* (October 29, 1996) 1005a

Appendix I — Section 1 of the Natural Gas Act, 15 U.S.C.A. § 717 (1994) 1007a

Appendix J — Section 2 of the Natural Gas Act, 15 U.S.C.A. § 717a (1994) 1010a

Appendix K — Section 4 of the Natural Gas Act, 15 U.S.C.A. § 717c (1994) 1012a

Appendix L — Section 5 of the Natural Gas Act, 15 U.S.C.A. § 717d (1994) 1017a

Appendix M — Section 7 of the Natural Gas Act, 15 U.S.C.A. § 717f (1994) 1019a

APPENDIX A — OPINION — *UNITED DISTRIBUTION COMPANIES v. FEDERAL ENERGY REGULATORY COMMISSION*, 88 F.3d 1105 (D.C. Cir. 1996)

UNITED DISTRIBUTION COMPANIES, Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION, Respondent.

Windward Energy & Marketing Company, et al., Intervenors.

Nos. 92-1485, 92-1495, 92-1496, 94-1171, 94-1173 to 94-1181, 94-1183 to 94-1185, 94-1187 to 94-1190, 94-1193, 94-1194, 94-1196 to 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231 to 94-1234, 94-1236 to 94-1243, 94-1246 to 94-1249, 94-1252, 94-1256 to 94-1259, 94-1263 to 94-1265, 94-1267 and 94-1270.

United States Court of Appeals,
District of Columbia Circuit.

Argued Feb. 21, 1996.

Decided July 16, 1996.

As Amended Oct. 29, 1996.

88 F.3d 1105 (D.C. Cir. 1996)

* * *

Appendix A

On Petitions for Review of Orders of the Federal Energy Regulatory Commission.

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Appearances were also filed by Carl M. Fink, Howard E. Shapiro, James C. Moffatt, Jennifer B. Corwin, Robert A. Nuernberg, Ronald D. Eastman, Oleta J. Harden, Barbara K. Heffernan, Cheryl L. Jones, Tom Rattray, Gearold L. Knowles, Margaret Ann Samuels, David C. Dickey, Thomas E. Hirsch, III, Britton White, Jr., James D. Senger, James J. Flood, Joel F. Zipp, Leja D. Courter, Ronald E. Christian, James C. Moffatt, Shippen Howe, John R. Staffier, Robert A. Nelson, Timothy C. Bladek, Andrew N. Greene, Edward B. Myers, Carolyn Y. Thompson, Kenneth D. Brown, Frank R. Lindh, Keith T. Sampson, Raymond N. Shibley, Cheryl J. Walker, Thomas J. Eastment, Michael L. Pate, Barbara S. Jost, Michael E. Small,

Appendix A

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Before: WALD, SENTELLE and ROGERS, Circuit Judges.

Opinion for the Court filed PER CURIAM.*

* * *

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* Parts III and V.A-B, E.3-4 and F are by Judge Wald; Parts IV and V.C-D and E.1-2 are by Judge Sentelle; and Parts I and II are by Judge Rogers.

Appendix A

PER CURIAM:

I. Introduction

In Order No. 636,[1] the Federal Energy Regulatory Commission ("Commission" or "FERC") took the latest step in its decade-long restructuring of the natural gas industry, in which the Commission has gradually withdrawn from direct regulation of certain industry sectors in favor of a policy of "light-handed regulation" when market forces make that possible. We review briefly the regulatory background for natural gas.

A. *Background: Natural Gas Industry Structure*

The natural gas industry is functionally separated into production, transportation, and distribution. Traditionally, before the move to open-access transportation, a producer extracted the gas and sold it at the wellhead to a pipeline company. The pipeline company then transported the gas through high-pressure pipelines and re-sold it to a local distribution company (LDC). The LDC in turn distributed the gas through its local mains to residential and industrial users. *See generally* EDWARD C. GALLICK, COMPETITION IN THE NATURAL GAS INDUSTRY 9-12 (1993).

The Natural Gas Act (NGA), ch. 556, 52 Stat. 821 (1938)

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1. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939, order on reh'g, Order No. 636-A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950, *order on reh'g*, Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *reh'g denied*, 62 F.E.R.C. ¶ 61,007 (1993).

(codified as amended at 15 U.S.C. §§ 717-717w (1994)), enacted in 1938, gave the Commission jurisdiction over sales for resale in interstate commerce and over the interstate transportation of gas, but left the regulation of local distribution to the states.[2] NGA § 1(b), 15 U.S.C. § 717(b). The NGA was intended to fill the regulatory gap left by a series of Supreme Court decisions that interpreted the dormant Commerce Clause to preclude state regulation of interstate transportation and of wholesale gas sales. *See Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377- 80, 103 S.Ct. 1905, 1908-10, 76 L.Ed.2d 1 (1983). The overriding purpose of the NGA is " 'to protect consumers against exploitation at the hands of natural gas companies.' " *FPC v. Louisiana Power & Light Co.*, 406 U.S. 621, 631, 92 S.Ct. 1827, 1833, 32 L.Ed.2d 369 (1972) (quoting *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 610, 64 S.Ct. 281, 291, 88 L.Ed. 333 (1944)). Federal regulation of the natural gas industry is thus designed to curb pipelines' potential monopoly power over gas transportation.[3] The enormous economies of scale involved in the construction of natural gas pipelines tend to make the transportation of gas a natural monopoly.[4] Indeed, even with

2. In 1954, Congress added the "Hinshaw exemption," which excludes from the Commission's jurisdiction gas that is received within a state (or at the state boundary) and is consumed within that state, provided that the gas is subject to state regulation. NGA § 1(c), 15 U.S.C. § 717(c).

3. The seminal analysis of pipelines' market power over transportation can be found in the Federal Trade Commission (FTC) report that led to the enactment of the NGA. *See* SEN. DOC. NO. 92, pt. 84A, 70th Cong., 1st Sess. (1935).

4. A natural monopoly occurs when, because of the high ratio of fixed costs to variable costs, a single firm has declining average costs at the level of demand in the industry, such that the single firm can supply the service more cheaply than two firms could. RICHARD A. POSNER, ECONOMIC ANALYSIS OF LAW § 12.1, at 343-45 (4th ed.1992).

the expansion of the national pipeline grid, or network, in recent decades, many "captive" customers[5] remain served by a single pipeline.[6] Order No. 436, ¶ 30,665, at 31,473.[7]

Even though the market function potentially subject to monopoly power is the transportation of gas, for many years the Commission also regulated the price and terms of sales by producers to interstate pipelines. *See Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 677-84, 74 S.Ct. 794, 796-800, 98 L.Ed. 1035 (1954). Producer price regulation was widely regarded as a failure, introducing severe distortions into what otherwise would have been a well-functioning producer sales

5. We use the term "captive customer" to refer to customers "who must use gas and can only obtain it from one provider." *Mississippi Valley Gas Co. v. FERC*, 68 F.3d 503, 506 (D.C.Cir.1995); *see also Wisconsin Gas Co. v. FERC*, 770 F.2d 1144, 1150, 1160 (D.C.Cir.1985) ("[F]ull requirements [or 'captive'] customers purchase their entire natural gas supply from one pipeline and, because of their geographical location, are unable to swing off the system to obtain cheaper supplies of gas.").

6. As of 1985, 10% of gas deliveries were to LDCs served by four or more pipelines, 39.5% to LDCs served by three pipelines, 28% to LDCs served by two pipelines, and 22.5% to LDCs served by a single pipeline. STEPHEN F. WILLIAMS, THE NATURAL GAS REVOLUTION OF 1985, at 4 (1985).

7. Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,665, order on reh'g, Order No. 436-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,688, order on reh'g, Order No. 436-C, 34 F.E.R.C. ¶ 61,404, *order on reh'g*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405, *order on reh'g*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986), *vacated and remanded sub nom. Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C.Cir.1987) (AGD I), *cert. denied*, 485 U.S. 1006, 108 S.Ct. 1468, 1469, 99 L.Ed.2d 698 (1988).

market. *See* STEPHEN G. BREYER & PAUL W. MACAVOY, ENERGY REGULATION BY THE FEDERAL POWER COMMISSION 56-88 (1974). When a severe gas shortage developed in the 1970s, Congress enacted the Natural Gas Policy Act of 1978 (NGPA), Pub.L. No. 95-621, 92 Stat. 3351 (codified as amended at 15 U.S.C. §§ 3301-3432 (1994)), which gradually phased out producer price regulation. Under the NGPA's partially regulated producer-price system, many pipelines entered into long-term contractual obligations, in what were known as "take-or-pay" provisions, to purchase minimum quantities of gas from producers at costs that proved to be well above current market prices of gas. *See* Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 ENERGY L.J. 1, 11-16 (1988).

The problem of pipelines' take-or-pay settlement costs has plagued the industry and the Commission over the last fifteen years. The Commission's initial response to escalating pipeline take-or-pay liabilities was to authorize pipelines to offer less expensive sales of third-party (non-pipeline-owned) gas to non-captive customers while still offering only higher-priced pipeline gas to captive customers.[8] The court struck down these measures

8. First, the Commission approved special marketing programs, under which pipelines agreed to transport third-party gas to industrial end-users in exchange for the producer's agreement to credit the transported gas to the pipeline's take-or-pay liability. *See Columbia Gas Transmission Corp.*, 25 F.E.R.C. ¶ 61,220, *order on reh'g*, 25 F.E.R.C. ¶ 61,401 (1983), *order on reh'g*, 26 F.E.R.C. ¶ 61,031 (1984). Second, the Commission authorized selective transportation programs, under which a pipeline received a blanket certificate to transport third-party gas and was allowed to offer this service to its customers on a selective basis. *See* Order No. 234-B, *Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors*, [Regs. Preambles 1982-85] F.E.R.C.

(Cont'd)

because the Commission "ha[d] not adequately attended to the agency's prime constituency," captive customers vulnerable to pipelines' market power. *Maryland People's Counsel v. FERC*, 761 F.2d 780, 781 (D.C.Cir.1985) (MPC II); *see also Maryland People's Coun*sel v. FERC, 761 F.2d 768, 776 (D.C.Cir.1985) (MPC I). In response to the court's decisions in MPC I and MPC II, the Commission embarked on its landmark Order No. 436 rulemaking. See Order No. 436, ¶ 30,665, at 31,467.

B. *Order No. 436: Open-Access Transportation*

In Order No. 436, the Commission began the transition toward removing pipelines from the gas-sales business and confining them to a more limited role as gas transporters. Under a new Part 284 of its regulations,[9] the Commission conditioned receipt of a blanket certificate for firm transportation of third-party gas on the pipeline's acceptance of non-discrimination requirements guaranteeing equal access for all customers to the

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Stats. & Regs. (CCH) ¶ 30,476 (1983); Order No. 319, *Sales and Transportation by Interstate Pipelines and Distributors*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,477, *order on reh'g*, Order No. 319-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,512 (1983).

9. Customers who receive service under a blanket certificate as authorized in Order No. 436 are known as Part 284 customers. Customers who receive individually certificated service, to which the open-access conditions do not apply, are known as Part 157 customers, or § 7(c) customers. Although the Commission's current policy is no longer to issue Part 157 certificates, *Blue Lake Gas Storage Co.*, 59 F.E.R.C. ¶ 61,118, *reh'g denied*, 61 F.E.R.C. ¶ 61,284 (1992), existing Part 157 certificates remain in effect.

new service.[10] Order No. 436, ¶ 30,665, at 31,497-518. In effect, the Commission for the first time imposed the duties of common carriers upon interstate pipelines. *See Associated Gas Distributors v. FERC*, 824 F.2d 981, 997 (D.C.Cir.1987) (*AGD I*), *cert. denied*, 485 U.S. 1006, 108 S.Ct. 1468, 1469, 99 L.Ed.2d 698 (1988). By recognizing that anti-competitive conditions in the industry arose from pipeline control over access to transportation capacity, the equal-access requirements of Order No. 436 regulated the natural-monopoly conditions directly. In addition, every open-access pipeline was required to allow its existing bundled firm-sales customers to convert to firm-transportation service and, at the customer's option, to reduce its firm-transportation entitlement (its "contract demand"). Order No. 436, ¶ 30,665, at 31,518-33. Moreover, the Commission established a flexible rate structure under which transportation charges were limited to the maximum approved rate (based on fully allocated costs) but pipelines could selectively discount down to the minimum approved rate (based on average variable cost). *Id.* at 31,533-49.

The court largely approved Order No. 436, but the principal stumbling-block was the unresolved problem of uneconomical pipeline-producer contracts in the transition to the unbundled environment. The Commission had decided not to provide pipelines with relief from their take-or-pay liabilities, even though the introduction of open-access transportation in Order No. 436 would likely exacerbate the problem by reducing pipeline sales.[11] *AGD I*, 824 F.2d at 1021-23. After the court

10. Pipelines generally offer two forms of transportation service: firm transportation, for which delivery is guaranteed, and interruptible transportation, for which delivery can be delayed if all the capacity on the pipeline is in use.

11. The Commission limited itself to re-affirming a previous policy (Cont'd)

remanded the case on the ground that the Commission's inaction on take-or-pay did not exhibit reasoned decision making in light of open access, *id.* at 1030, the Commission adopted various interim measures in Order No. 500.[12] First, it instituted a "crediting mechanism," under which a pipeline could apply any third-party gas that it transported toward the pipeline's minimum-purchase obligation from that particular producer. Order No. 500, ¶ 30,761, at 30,779-84. Second, the Commission adopted two alternative cost-recovery mechanisms. As customary, a pipeline could recover all of its prudently incurred costs in its commodity (sales) charges, although that could prove difficult for pipelines with shrinking sales-customer bases. In the alternative, under the equitable- sharing approach, a pipeline offering open-access transportation could, if it voluntarily absorbed between twenty-five and fifty percent of the costs, recover an equal share of the costs through a "fixed charge" and recover the remaining amount (up to fifty percent) through a volumetric surcharge based on total throughput (and thus borne

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statement on take-or-pay liabilities that deferred the issue to individual rate-case filings. Order No. 436, ¶ 30,665, at 31,560-69; *see Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,637 (1985); 18 C.F.R. § 2.76.

12. Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,761, *order on reh'g*, Order No. 500-A, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH)P 30,770, *order on reh'g*, Order No. 500-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,772, *order on reh'g*, Order No. 500-C, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,786 (1987), *order on reh'g*, Order No. 500-D, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,800, *order on reh'g*, Order No. 500-E, 43 F.E.R.C. ¶ 61,234, *order on reh'g*, Order No. 500-F,

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by both sales and transportation customers alike).[13] *Id.* at 30,784-92; 18 C.F.R. § 2.104. Third, the Commission authorized pipelines not recovering take-or-pay costs in any other manner to impose a "gas inventory charge" (GIC), a fixed charge for "standing ready" to deliver gas — the sales analogue to a reservation charge. Order No. 500, ¶ 30,761, at 30,792-94; 18 C.F.R. § 2.105.

The Commission's alternative solutions to the problem of take-or-pay settlement costs in Order No. 500 fared poorly on judicial review. First, the court remanded the crediting mechanism for an explanation of whether the Commission had the requisite authority under § 7 of the NGA. *American Gas Ass'n v. FERC*, 888 F.2d 136, 148-49 (D.C.Cir.1989) (AGA I). After the Commission explained its § 7 authority for the crediting mechanism in Order No. 500-H,[14] the court upheld the crediting mechanism.[15] *American Gas Ass'n v. FERC*, 912 F.2d 1496,

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[Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,841 (1988), *order on reh'g*, Order No. 500-G, 46 F.E.R.C. ¶ 61,148, *vacated and remanded sub nom. American Gas Ass'n v. FERC*, 888 F.2d 136 (D.C.Cir.1989) (*AGA I*).

13. The remaining costs "may be recovered either through a commodity rate surcharge or a volumetric surcharge on total throughput." 18 C.F.R. § 2.104(a). In *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1299- 1300 (D.C.Cir.1992), the court upheld the Commission's reading of its regulation that a commodity rate surcharge must also be based on total throughput.

14. Order No. 500-H, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,867 (1989), *order on reh'g*, Order No. 500-I, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. ¶ 30,880, *remanded sub nom. American Gas Ass'n v. FERC*, 912 F.2d 1496 (D.C.Cir.1990) (*AGA II*).

15. The Commission terminated the crediting mechanism as of
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1509-13 (D.C.Cir.1990) (AGA II). Second, the court struck down the equitable-sharing cost-recovery mechanism on the ground that the Commission's "purchase deficiency" method for calculating the "fixed charge," which assigned costs to each customer based on how much its purchases had declined over the relevant preceding period, violated the filed-rate doctrine. *Associated Gas Distributors v. FERC*, 893 F.2d 349, 354-57 (D.C.Cir.1989) (*AGD II*), *reh'g en banc denied*, 898 F.2d 809 (D.C.Cir.), *cert. denied*, 498 U.S. 907, 111 S.Ct. 277, 278, 112 L.Ed.2d 233 (1990). The Commission responded to the invalidation of the "purchase deficiency" method in *AGD II* by adopting Order No. 528,[16] which allowed pipelines, in the "fixed charge," to pass through a portion of costs to customers based on any of several measures of current (rather than past) demand or usage, with the intent of avoiding the filed-rate problem. Order No. 528, ¶ 61,163, at 61,597-98. Finally, the court struck down the Commission's approval of a GIC on a particular pipeline because it had given undue weight to the pipeline's customers' having agreed to the GIC and failed adequately to consider the interests of end-users. *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1003-05 (D.C.Cir.1990).

Congress completed the process of deregulating the producer sales market by enacting the Natural Gas Wellhead Decontrol Act of 1989, Pub.L. No. 101-60, 103 Stat. 157

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December 31, 1990. Order No. 500-K, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,917, *reh'g denied*, Order No. 500-L, 55 F.E.R.C. ¶ 61,489 (1991).

16. Order No. 528, *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 53 F.E.R.C. ¶ 61,163 1990 WL 488926 (1990), *order on reh'g*, Order No. 528-A, 54 F.E.R.C. ¶ 61,095, *reh'g denied*, Order No. 528-B, 55 F.E.R.C. ¶ 61,372 (1991).

(codified in scattered sections of 15 U.S.C.). As the House Committee on Energy and Commerce emphasized, the Commission's creation of open-access transportation was "essential" to Congress' decision completely to deregulate wellhead sales. H.R.REP. NO. 29, 101st Cong., 1st Sess. 6 (1989), U.S.Code Cong. & Admin.News 1989, pp. 51, 56. The committee report declared also that "[b]oth the FERC and the courts are strongly urged to retain and improve this competitive structure in order to maximize the benefits of decontrol."[17] *Id.* The committee expected that, by ensuring that "[a]ll buyers [are] free to reach the lowest-selling producer," *id.*, open-access transportation would allow the more efficient producers to emerge, leading to lower prices for consumers, *id.* at 3, 7.

C. *Order No. 636: Mandatory Unbundling*

In Order No. 636, the Commission declared the open-access requirements of Order No. 436 a partial success. The Commission found that pipeline firm sales, which in 1984 had been over 90 percent of deliveries to market, had declined by 1990 to 21 percent. Order No. 636, ¶ 30,939, at 30,399 tbl. 1. On the other hand, only 28 percent of deliveries to market in 1990 were firm transportation, whereas 51 percent of deliveries used interruptible transportation. *Id.* at 30,399 & n. 61. The Commission concluded that many customers had not taken advantage of Order No. 436's option to convert from firm-sales to firm-transportation service because the firm-transportation component of bundled firm-sales service was "superior in

17. The committee added that "[t]his legislation does not deregulate gas pipelines, and the Committee will continue its oversight of the FERC to ensure that captive residential consumers are not disadvantaged, and that the current competitive 'open access' pipeline system is maintained." H.R.REP. NO. 29, *supra*, at 4, U.S.CODE CONG. & ADMIN.NEWS 1989, P. 53.

quality" to stand-alone firm-transportation service. *Id.* at 30,402. In particular, the Commission found that stand-alone firm-transportation service was often subject to daily scheduling and balancing requirements, as well as to penalties for variances from projected purchases in excess of ten percent. Moreover, pipelines usually did not offer storage capacity on a contractual basis to stand-alone firm-transportation shippers. *Id.* The result was that many of the non-converted customers used the pipelines' firm-sales service during times of peak demand but in non-peak periods bought third-party gas and transported it with interruptible transportation. The Commission found that "[i]t is often cheaper for pipeline sales customers to buy gas on the spot market, and pay the pipeline's demand charge plus the interruptible rate, than to purchase the pipeline's gas." *Id.* at 30,400. Because of the distortions in the sales market, these customers often paid twice for transportation services and still received an inferior form of transportation (interruptible rather than firm). *Id.* Because of the anti-competitive effect on the industry, the Commission found that pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA. *Id.* at 30,405.

The Commission's remedy for these anti-competitive conditions, and the principal innovation of Order No. 636, was mandatory unbundling of pipelines' sales and transportation services. By making the separation of the two functions mandatory, the Commission expects that pipelines' monopoly power over transportation will no longer distort the sales market. Order No. 636, ¶ 30,939, at 30,406-13; Order No. 636-A, ¶ 30,950, at 30,527-46; Order No. 636- B, ¶ 61,272, at 61,988-92. To replace the firm-transportation component of bundled firm-sales service, the Commission introduced the concept of "no-notice firm transportation," stand-alone firm transportation without penalties. Those customers who receive bundled firm-

sales service have the right, during the restructuring process, to switch to no-notice firm-transportation service. Pipelines that did not offer bundled firm-sales service are not required to offer no-notice transportation; but if they do, they must offer no-notice transportation on a non-discriminatory basis. Order No. 636, ¶ 30,939, at 30,421-25; Order No. 636-A, ¶ 30,950, at 30,570-77; Order No. 636-B, ¶ 61,272, at 62,006-10; *see* 18 C.F.R. § 284.8(a)(4).

In contrast to the continued regulation of the transportation market, the Commission essentially deregulated the pipeline sales market. The Commission issued every Part 284 pipeline a blanket certificate authorizing gas sales. Although acknowledging that "only Congress can 'deregulate,' " the Commission "institut[ed] light-handed regulation, relying upon market forces at the wellhead or in the field to constrain unbundled pipeline sale for resale gas prices within the NGA's 'just and reasonable' standard." Order No. 636, ¶ 30,939, at 30,440. The Commission reasoned that open-access transportation, combined with its finding that "adequate divertible gas supplies exist in all pipeline markets," would ensure that the free market for gas sales would keep rates within the zone of reasonableness. *Id.* at 30,437-43; Order No. 636-A, ¶ 30,950, at 30,609-24; Order No. 636-B, ¶ 61,272, at 62,024-25; *see* 18 C.F.R. §§ 284.281-284.288.

The Commission also undertook several measures to ensure that the pipeline grid, or network, functions as a whole in a more competitive fashion. First, open-access pipelines may not inhibit the development of "market centers," which are pipeline intersections that allow customers to take advantage of many more transportation routes and choose between sellers from different natural gas production areas. Similarly, open-access

pipelines may not interfere with the development of "pooling areas," which allow the aggregation of gas supplies at a production area. Order No. 636, ¶ 30,939, at 30,427-28; Order No. 636- A, ¶ 30,950, at 30,581-82; Order No. 636-B, ¶ 61,272, at 62,011-12; *see* 18 C.F.R. §§ 284.8(b)(6), 284.9(b)(5). Finally, as part of the move toward open-access transportation, the Commission required Part 284 pipelines to allow shippers to deliver gas at any delivery point without penalty and to allow customers to receive gas at any receipt point without penalty. Order No. 636, ¶ 30,939, at 30,428-29; Order No. 636-A, ¶ 30,950, at 30,582-86; Order No. 636-B, ¶ 61,272, at 62,012-13; *see* 18 C.F.R. § 284.221(g)-(h).

Even though this is the court's first occasion to address Order No. 636, which was enacted in 1992, we do not write on a clean slate. Beginning with MPC I and MPC II, the court has consistently required the Commission to protect consumers against pipelines' monopoly power. No longer reluctantly engaged in the unbundling enterprise, the Commission has responded by initiating sweeping changes with Order No. 636. Accordingly, we review the Commission's exercise of its authority under the NGA in light of the principles that the court has already applied in this area.

D. *Issues on Review and Conclusions*

After two comprehensive rehearing orders, Orders No. 636-A and No. 636-B, the Commission denied further rehearing.[18]

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18. The Commission has modified its Part 284 regulations in two rulemakings since Order No. 636 that are not on review in this proceeding. First, the Commission adopted further standards for the electronic bulletin boards used for capacity release. Order No. 563, *Standards for Electronic*

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62 F.E.R.C. ¶ 61,007 (1993). The Judicial Panel on Multidistrict Litigation consolidated all the petitions for review of the Order No. 636 series and transferred them to the Eleventh Circuit by random selection pursuant to 28 U.S.C. § 2112(a)(3). On February 15, 1994, the Eleventh Circuit transferred the petitions for review to this court. We consolidated with this case petitions for review of the Commission's decision to prohibit buy/sell agreements,[19] and of the Commission's decision to end capacity-brokering programs.[20] We ordered the petitioners to file briefs in consolidated industry groups: pipelines; local distribution companies (LDCs); small distributors and municipalities; industrial end-users; electric generators; and public utility commissions (PUCs).[21]

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Bulletin Boards Required Under Part 284 of the Commission's Regulations, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,988 (1993) (amending 18 C.F.R. §§ 284.8(b)(4)-(5), 284.9(b)(4)), *order on reh'g*, Order No. 563- A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,994, *reh'g denied*, 68 F.E.R.C. ¶ 61,002 (1994). Second, the Commission modified the short-term exception to the capacity-release rules. Order No. 577, *Release of Firm Capacity on Interstate Natural Gas Pipelines*, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 31,017 (amending 18 C.F.R. § 284.243(h)(1)), *order on reh'g*, Order No. 577-A, [Current] F.E.R.C. Stats. & Regs. ¶ 31,021 (1995).

19. *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,031, *order on reh'g*, 60 F.E.R.C. ¶ 61,117 (1992).

20. *Algonquin Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,032, *reh'g denied*, 60 F.E.R.C. ¶ 61,113 (1992).

21. The court also received separate petitioners' briefs from Carnegie Natural Gas Company, an interstate pipeline company; Elizabethtown Gas Company, a local distribution company; Hadson Gas Systems, Inc., a "marketer" that buys and re-sells pipeline transportation capacity; and Meridian Oil Inc., also a marketer.

Appendix A

The petitioners do not challenge the mandatory unbundling remedy itself. At issue on review are numerous other aspects of Order No. 636 involving changes that the Commission undertook as part of its comprehensive restructuring of the natural gas industry. In Part II of our opinion, we discuss the challenges to the Commission's rules on Part 284 firm transportation. Part III addresses the challenges to the Commission's new capacity-release program. Part IV covers the requirement that pipelines use the straight fixed/variable rate-design methodology. Finally, in Part V we deal with challenges to the Commission's handling of transition costs.

As we discuss in Part II.A, the petitioners challenge four peripheral aspects of the Commission's unbundling remedy. We uphold the Commission's rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer. *See* 18 C.F.R. § 284.14(e). Further, insofar as the Commission may have stated that a § 7(b) abandonment proceeding is never required for pipeline changes to contract-storage withdrawal and injection schedules, we grant relief, but we defer review of possible challenges to specific pipeline changes. The challenge to the Commission's rule that transportation-only pipelines may not acquire capacity on other pipelines has been rendered moot by virtue of an intervening Commission decision. We remand for further explanation the Commission's decision that only those customers who received bundled firm-sales service on May 18, 1992, are entitled to the new no-notice transportation service.

Part II.B concerns the Commission's award of pre-granted abandonment to long-term firm-transportation service, subject to the existing shipper's "right of first refusal" (ROFR). Under this provision of the rules, pipelines are no longer required to

go through § 7 abandonment proceedings when a transportation contract expires. In return, the existing customer has the right to retain service if it matches the terms of a competing offer for that capacity. Such bids are capped at the maximum rate approved by the Commission for that service, and the contract length may not exceed twenty years. Order No. 636, ¶ 30,939, at 30,448-52; Order No. 636-A, ¶ 30,950, at 30,627-36; Order No. 636- B, ¶ 61,272, at 62,025-28; *see* 18 C.F.R. § 284.221(d). While we conclude that in its basic structure the right-of-first-refusal mechanism complies with § 7, we remand the right-of-first-refusal mechanism to the Commission for further explanation of why it adopted a twenty-year term-matching cap. We uphold the Commission's decision not to require pipelines to discount rates in the right-of-first-refusal process.

The Commission also re-visited its policies for the curtailment of gas in times of a supply shortage or a capacity interruption. Gas can be curtailed on an end-use basis, meaning that high-priority users have priority in times of curtailment, or on a pro rata basis, meaning that each user's deliveries are curtailed proportionally. The Commission found that it was statutorily obligated to require pipelines to adopt an end-use curtailment plan for shortages in the supply of pipeline gas. On the other hand, the Commission declined to require pipelines to adopt end-use curtailment for capacity interruption. Order No. 636, ¶ 30,939, at 30,429-31; Order No. 636-A, ¶ 30,950, at 30,586-93. In Part II.C, we affirm the Commission's decision that title IV of the NGPA requires end-use supply curtailment and conclude that the issue of curtailment compensation is not ripe for review. We also deny the petitions for review of the Commission's capacity-curtailment policies, but we do not examine whether pure pro rata capacity curtailment is always appropriate because the Commission has examined that issue

on a pipeline-specific basis in the restructuring proceedings. Finally, we uphold the Commission's policies for supply shortages of third-party gas. Part III addresses the Commission's adoption of a uniform capacity-release program — a regulated market that allows capacity-holders to re-sell the rights to pipeline firm-transportation capacity. An existing shipper that finds itself with excess capacity may list that capacity on the pipeline's electronic bulletin board (EBB), which functions as a central clearinghouse for the secondary capacity market. Order No. 636, ¶ 30,939, at 30,416-21; Order No. 636-A, ¶ 30,950, at 30,550-65; Order No. 636-B, ¶ 61,272, at 61,994-62,003; *see* 18 C.F.R. § 284.243. We uphold the Commission's jurisdiction to regulate the re-sale of interstate-transportation rights in general, as well as specifically its jurisdiction over LDCs who broker capacity to local end-users and over municipal LDCs. We also uphold the Commission's decision that state-authorized "buy/sell arrangements"[22] are pre-empted by the Commission's capacity-release program. Finally, we uphold the Commission's decision to exclude Part 157 shippers and conclude that other challenges to the substance of the capacity-release program are not ripe for review.

Part IV deals with the Commission's requirement that pipelines adopt a new rate-design methodology known as straight fixed/variable (SFV).[23] Under SFV, pipelines must allocate fixed

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22. A buy/sell arrangement is an agreement between an LDC and one of its local end-users under which (1) the end-user identifies (and sometimes purchases) gas held by a producer, (2) the LDC in turn purchases the identified gas and uses its firm-transportation capacity to transport the gas, and (3) the LDC sells the gas to the end-user.

23. The Commission recently issued a policy statement approving the use of market-based rates for transportation services, analogous to the market-

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costs to the reservation charge, and variable costs to the usage charge.[24] The Commission mandated SFV so that fixed costs, which vary greatly between pipelines, would no longer affect the usage charge and thus distort the national gas-sales market that Order No. 636 fosters. Because the shift from the previous modified fixed/ variable (MFV) rate design[25] would disadvantage low-load-factor customers,[26] the Commission adopted various

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based rates for pipeline gas sales, seesupra at 61-62, but only if the pipeline can demonstrate that it lacks significant market power over the transportation service. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076, *reh'g denied*, 75 F.E.R.C. ¶ 61,024 (1996). This policy statement is not on review in this proceeding, and we review only the Commission's requirement that pipelines use SFV rate design.

24. The reservation, or demand, charge is for reserving firm-transportation capacity; the usage, or commodity, charge is for the actual transportation of gas.

25. Under the previously effective MFV rate design, pipelines assigned most fixed costs to the reservation charge, but return on equity and related taxes were assigned along with variable costs to the usage charge. According to one study, the practical result was that under MFV about 15% to 20% of fixed costs were assigned to the usage charge. GENERAL ACCOUNTING OFFICE, NATURAL GAS: COSTS, BENEFITS AND CONCERNS RELATED TO FERC'S ORDER 636, at 33 n.11 (Nov.1993). In addition, under MFV rate design the reservation charge was divided into two equal components: the "D-1 charge" was based on a customer's daily contract demand, or entitlement, and the "D-2 charge" was based on a customer's actual annual usage.

26. A customer's load factor is the ratio between its average usage and its peak usage. Customers with seasonal usage fluctuations, such as LDCs, have low load factors, whereas customers with constant usage throughout the year, such as industrial end-users, have high load factors.

SFV mitigation measures to protect those customers. Order No. 636, ¶ 30,939, at 30,431-37; Order No. 636- A, ¶ 30,950, at 30,593-609; Order No. 636-B, ¶ 61,272, at 62,013-24; *see* 18 C.F.R. § 284.8(d). We uphold the Commission's authority under § 5 to adopt SFV rate design and conclude that substantial evidence supports the Commission's findings that MFV rate design distorted the producer sales market and that SFV is an appropriate rate-design methodology. Although we uphold the Commission's SFV mitigation measures against most challenges, we conclude that the Commission failed to explain why it ordered some mitigation measures on an individual-customer basis and others on a customer-class basis and why it did not require pipelines to offer small-customer discounts to former customers of downstream pipelines. Accordingly, we remand those issues to the Commission.

Finally, as we explain in Part V, the Commission addressed the transition costs involved with implementing Order No. 636. The Commission allowed pipelines, whose role as gas merchants was greatly reduced, to pass through to transportation customers all the costs of reducing contractual purchase obligations from producers, known as gas-supply realignment (GSR) costs. Unlike the Order No. 500 equitable-sharing cost-recovery mechanism for take-or-pay costs from pipeline-producer contracts, Order No. 636 imposes all the costs of realigning unneeded producer-pipeline contracts on pipeline customers. The Commission authorized pipelines to recover 90% of the GSR costs from current firm-transportation customers (including customers who converted from being bundled firm-sales customers under Order No. 436) and 10% of the GSR costs from interruptible-transportation customers. Order No. 636, ¶ 30,939, at 30,457-62; Order No. 636-A, ¶ 30,950, at 30,641-64; Order No.636-B, ¶ 61,272, at 62,031-45. We uphold the Commission's decision

to allow pipelines to recover GSR costs from customers who converted to open-access transportation before Order No. 636, but remand the decision that pipelines must allocate 10% of GSR costs to interruptible-transportation customers for further explanation. We also remand the decision that pipelines can pass through all their GSR costs to customers for further consideration by the Commission in light of the equitable-sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636. We affirm the Commission's treatment of LDC by-pass, GSR costs for the Great Plains coal gasification project, and stranded costs.

The Commission resolved issues that it considered generic to all pipelines in the Order No. 636 rulemaking, but deferred many issues associated with the implementation of mandatory unbundling to restructuring proceedings. Every Part 284 pipeline is required to go through an individual pipeline restructuring proceeding, to conform its operations to the new regulations and to address pipeline-specific issues. 18 C.F.R. § 284.14; Order No. 636, ¶ 30,939, at 30,462-69; Order No. 636-A, ¶ 30,950, at 30,664-73. The Commission has by now completed the restructuring proceedings, and in the proceedings for some pipelines interested parties have petitioned for review.[27] In this decision, we review only the Order No. 636 rulemaking, although on some issues we have necessarily had to consider the interaction between the rulemaking and the subsequent restructuring proceedings.

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27. The court has docketed the petitions for review of the restructuring proceedings in *UGI Utilities v. FERC*, No. 93-1291, and held them in abeyance until our decision.

II. Open-Access Firm Transportation

A. *Unbundling*

The petitioners challenge four aspects of the Commission's unbundling remedy: the rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer; the Commission's policy on pipelines' ability to modify existing storage contracts without abandonment proceedings; the rule that transportation-only pipelines may not acquire capacity on other pipelines; and the eligibility date for no-notice transportation service.

1. *Prohibition on unilateral customer release of transportation capacity*

When the Commission concluded that the pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA, Order No. 636, ¶ 30,939, at 30,405, the Commission found also that "the continued enforcement of a pipeline sales customer's purchase obligations, agreed to before implementation of unbundling under this rule, is unjust and unreasonable, and unduly discriminatory." *Id.* at 30,453. Accordingly, all existing bundled firm-sales customers were given the option to reduce or terminate their contractual purchase obligations during the pipeline's restructuring proceedings. 18 C.F.R. § 284.14(d)(1). By contrast, those customers were not relieved of their contractual transportation obligations unless either an alternative, creditworthy shipper offered to assume the capacity at the same or a higher rate (up to the maximum approved rate), or the pipeline agreed to reduce or terminate the transportation obligation. *Id.* § 284.14(e)(2). If a customer wished to reduce or terminate its transportation obligation, and either a

replacement shipper assumed the capacity or the pipeline agreed, then the pipeline was authorized to abandon the service under the prior contract. *Id.* § 284.14(e)(3). In effect, existing bundled firm-sales customers remained contractually bound to receive firm-transportation service on the pipeline. On rehearing, Northern Indiana Public Service Company (NIPSCO) maintained that the Commission's actions entirely abrogated the existing pipeline-customer bundled firm-sales contracts, and that the Commission could not require the LDCs to enter into new transportation contracts. The Commission denied that it had abrogated the contracts: the pipelines remained contractually obligated to provide separate sales and transportation services. "[T]he fact that LDCs have an opportunity to revise their sales entitlements under existing contracts with their pipeline suppliers does not mean they should also have an unqualified right to terminate their obligations for the costs of transportation capacity under those contracts." Order No. 636-A, ¶ 30,950, at 30,638. The Commission also explained that if it released former bundled-sales customers from transportation obligations, "these capacity costs could be shifted from the customer who has contracted for the capacity to the pipeline or other customers that have no need for the capacity." *Id.* at 30,637.

NIPSCO, joined by other LDC petitioners,[28] contends that, by holding pipeline customers to the transportation component of bundled firm-sales contracts, the Commission essentially imposed a new contract upon the customers, which is beyond the Commission's § 5 authority. Section 5(a) provides that, whenever the Commission has found that an existing contract is "unjust, unreasonable, unduly discriminatory, or preferential," it "shall determine the just and reasonable contract to be

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28. The other LDC petitioners are the Atlanta Gas Light Company and the Chattanooga Gas Company.

thereafter observed and in force, and shall fix the same by order." 15 U.S.C. § 717d(a). NIPSCO contests not the Commission's underlying finding that the bundled firm- sales contracts violated §§ 4(b) and 5(a), but only the remedy imposed under § 5. Our review is limited to whether the Commission's reading of § 5 to authorize it to hold LDCs to the remaining terms of a modified pipeline-customer contract is a reasonable construction of its statutory authority. *See AGD I*, 824 F.2d at 1001.

The bundled firm-sales contracts between pipelines and LDCs were subject to the Commission's § 5 authority. The regulatory structure of the Natural Gas Act is contract-based: it "permits the relations between the parties to be established initially by contract, the protection of the public interest being afforded by supervision of the individual contracts." *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 339, 76 S.Ct. 373, 378, 100 L.Ed. 373 (1956). Under § 5, "the Commission has plenary authority to limit or to proscribe contractual arrangements that contravene the relevant public interests." *Permian Basin Area Rate Cases*, 390 U.S. 747, 784, 88 S.Ct. 1344, 1369, 20 L.Ed.2d 312 (1968). For example, in *Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C.Cir.1985), *cert. denied*, 476 U.S. 1114, 106 S.Ct. 1968, 1969, 90 L.Ed.2d 653 (1986), the court affirmed the Commission's decision in Order No. 380 that "minimum bill" provisions in existing contracts were "unjust and unreasonable" under § 5.[29] The court upheld

29. Minimum bills were clauses in pipeline-customer contracts that "require[d] a pipeline customer to pay for a minimum volume of gas, whether or not the customer purchase[d] that amount of gas." *Wisconsin Gas Co.*, 770 F.2d at 1149. Thus, the minimum bills were analogous to the take-or- pay provisions in pipeline-producer contracts. But cf. *id.* at 1159-60. The Commission prohibited minimum bills because they allowed pipelines to collect substantial commodity charges for gas that was never delivered and

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the Commission's remedy, eliminating the minimum bill from the contracts, against the claim that such a remedy "unlawfully alter[ed] the terms of existing contracts," on the ground that "section 5 gives the Commission authority to alter terms of any existing contract found to be 'unjust' or 'unreasonable.' " *Id.* at 1153 n. 9.

NIPSCO also maintains that the Commission has construed its § 5 authority to extend beyond the limits in § 1(b) on the Commission's jurisdiction. Regardless of the Commission's authority to impose modified contractual obligations on pipelines, NIPSCO contends that the Commission lacks such authority over LDCs because LDCs are "non-jurisdictional" entities. Under § 1(b), the Commission's jurisdiction over "the transportation of natural gas in interstate commerce" does not apply to "the local distribution of natural gas or to the facilities used for such distribution." 15 U.S.C. § 717(b). But the local-distribution exception applies only to the movement of gas within an LDC's local mains and not to the movement of gas in high-pressure interstate pipelines. *FPC v. East Ohio Gas Co.*, 338 U.S. 464, 470-71, 70 S.Ct. 266, 269-70, 94 L.Ed. 268 (1950); *see also Louisiana Power & Light*, 406 U.S. at 636 & n. 13, 92 S.Ct. at 1836 & n. 13. Thus, for the same reasons that the

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because they "ha[d] become a major obstacle to the transmittal of clear market signals from the burner tip back to the well-head." Order No. 380, *Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,571, at 30,962, *order on reh'g*, Order No. 380-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,584, *order on reh'g*, 29 F.E.R.C. ¶ 61,076, *order on reh'g*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,607, *order on reh'g*, 29 F.E.R.C. ¶ 61,332 (1984), *affirmed in part and remanded in part sub nom. Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C.Cir.1985).

Commission has jurisdiction over the re-sale of interstate capacity rights by LDCs to local end-users, *see infra* Part III.B.2, it also has jurisdiction over an LDC's ability to reduce or terminate its contractual interstate-transportation obligation. The pipeline-LDC contracts for transportation through interstate pipelines do not fall within the local-distribution exception to the Commission's jurisdiction.

The Commission cannot use the pipeline-LDC contracts as a jurisdictional hook for non-jurisdictional measures that do not relate to the Commission's § 5 remedial authority over the contracts.[30] As the court has held in a different context, the Commission may not assert its jurisdiction over a party merely because it is "involved in a contractual relationship with a jurisdictional pipeline." *ARCO Oil & Gas Co. v. FERC*, 932 F.2d 1501, 1503 (D.C.Cir.1991). NIPSCO maintains that the Commission has done just that by replacing the agreed-upon contractual terms with entirely new terms of the Commission's own devising, when it would otherwise be without jurisdiction to compel the LDC to receive service in the first instance. But we do not agree that the Commission has overstepped the bounds of its § 5 authority in the first place. First, an LDC may maintain its original bargain by choosing not to exercise its unilateral right to terminate the purchase obligation. The resulting combination of sales service and no-notice firm-transportation service replicates its prior contractual entitlement. Thus, it is somewhat difficult to see the purported compulsion against LDCs in the Commission's decision not to grant them the right to terminate their transportation obligations. Second, the Commission's remedy was appropriately confined to the underlying violation. Because the Commission found the sales component of the bundled contracts to be unjust and

30. *See also infra* at 91 n. 57.

unreasonable, Order No. 636, ¶ 30,939, at 30,453, it interfered with existing contracts only to the extent necessary to remedy the effects of pipelines' market power. The Commission has the authority under § 5 to adopt a remedy proportionate to the problem being addressed. *AGD I*, 824 F.2d at 1019. Finally, § 5 instructs that "the Commission shall determine the just and reasonable . . . contract to be thereafter observedand in force, and shall fix the same by order." 15 U.S.C. § 717d(a). The limits of the Commission's authority to modify pipeline-LDC contracts under § 5 lie in the requirement that, given the original contract and the Commission's findings of unlawfulness, the resulting contract be "just and reasonable." NIPSCO does not contend that the result of unbundling the firm-sales contracts was unjust or unreasonable. We therefore uphold the Commission's § 5 authority to hold LDCs to the transportation component of the modified bundled firm-sales contracts.

NIPSCO contends in the alternative that, even if the Commission's action was within its § 5 authority, the Commission acted arbitrarily and capriciously. In NIPSCO's view, the limited nature of the remedy allows pipelines to continue to exercise market power over customers in the transportation contracts, in contravention of the overall goals of Order No. 636. We reject this challenge as well because the Commission has provided a reasonable basis for its decision not to allow customers unilaterally to reduce their contractual transportation obligations. *Cf. ARCO*, 932 F.2d at 1502.

The Commission found in Order No. 636 that "the amount of capacity reserved for pipeline firm sales still far exceeds the pipelines' actual sales so that capacity is not available for firm transportation and, as a result, interruptible transportation maintains a significant share of peak period transportation."

Order No. 636, ¶ 30,939, at 30,406. In other words, because many firm-sales customers decided to purchase third-party gas and transport it using interruptible service, those customers ended up holding excess reserved capacity. NIPSCO asserts that the effect of the Commission's decision not to allow LDCs unilaterally to reduce their contractual transportation obligations is to perpetuate customers' excessive capacity holdings. NIPSCO is correct insofar as the effect of any contract is to lock in current conditions, and the existence of a long-term contract necessarily slows the transition of a market to a new equilibrium when some underlying condition changes. Moreover, the capacity-release mechanism is an imperfect solution for the LDCs because the existing pipeline customer is unlikely to receive full compensation for released capacity in an excess-capacity market situation. Yet the problem of capacity excess that the Commission identified was that customers held more capacity in bundled-sales contracts than they purchased gas from the pipeline, not that customers held more firm-transportation capacity than needed for their peak demand. Contrary to NIPSCO's contention, there is no contradiction between the general goal in Order No. 636 of encouraging more efficient use of reserved capacity and the challenged rule that customers may not unilaterally release contractual transportation obligations: the Commission never found that the natural gas industry after mandatory unbundling would be characterized by excess reserved capacity.

Moreover, the Commission provided in Order No. 636-A a coherent rationale for its decision. Because a pipeline's rate structure is predicated upon levels of reserved capacity, providing customers with the unilateral option to reduce those levels would either reduce the pipeline's cost recovery or force

the pipeline to increase rates for the remaining customers.[31] Order No. 636- A, ¶ 30,950, at 30,637. Because someone has to bear the costs of unfavorable contractual capacity obligations, the Commission reasoned that the customer who voluntarily assumed those obligations by entering into the contract should bear those costs rather than spreading them over all of the pipeline's customers.

The Commission decided to modify the set of contracts that forms the structure of the natural gas industry only as much as necessary to alleviate the anti-competitive sales component of the bundled contracts. The Commission is not required to exercise its § 5 authority beyond the limits of the problem it has identified, *see AGD I*, 824 F.2d at 1019, and its cost-shifting rationale was a well-reasoned justification for its decision not to go further. We therefore uphold this portion of the rules.

2. *Pipeline modification of contract-storage rights*

Because the Commission found that "pipelines' superior rights with respect to access and control provide them with several advantages over other gas merchants with no access to storage for their gas," it required pipelines to offer access to their storage capacity on an open-access basis. Order No. 636, ¶ 30,939, at 30,425-26. By defining "transportation" to include "storage," 18 C.F.R. § 284.1(a), the Commission made storage subject to the same non-discrimination requirements as capacity

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31. The Commission also announced that the customer could negotiate an "exit fee" to induce the pipeline to release the customer from its contractual obligations. Order No. 636, ¶ 30,939, at 30,454. Whether the customer retains excess contractual capacity or negotiates a one-time exit fee, however, there is no reason why the cost to the customer should not be the same, discounted over time.

rights. *Id.* §§ 284.8(b), 284.9(b). Although pipelines were allowed to retain storage capacity for system management and in order to ensure the delivery of no-notice service, they were required to offer remaining storage capacity on an open-access contractual basis for customer-owned gas. Order No. 636, ¶ 30,939, at 30,426- 27. The Commission granted former bundled firm-sales customers a priority right to that storage capacity. Order No. 636-A, ¶ 30,950, at 30,578.

In its request for rehearing of Order No. 636, CNG Transmission Corporation, a pipeline company, explained that the changes involving open-access storage would create difficulties for it in providing the contractual levels of service to its existing contract-storage customers. Because "current contract storage injection and withdrawal schedules, and other related operational protocols, are based upon current levels of contract storage service," CNG requested the ability to modify existing storage customers' contractual rights to inject or withdraw gas. The Commission responded that its

> intent was that current contract storage customers retain their full right to capacity as specified in their contracts. The Commission did not mean to infer [sic] that the terms and conditions associated with their rights could not be changed if they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage. This, of course, is a pipeline specific matter and must be addressed in the restructuring proceeding.

Order No. 636-A, ¶ 30,950, at 30,579. Upon further rehearing, however, the Commission went further, stating that,

> while it has authorized pipelines to propose to change existing storage arrangements, if necessary, to provide no-notice transportation service, the pipeline must still show that the changes are necessary and reasonable. This includes an impact of a change on current contract storage customers. The Commission has not authorized any reduction in contract storage capacity. The Commission views changes to injection and withdrawal schedules as changes to terms and conditions, rather than to the level of certificated service. Hence, the Commission concludes that changes to existing contract storage terms and conditions will not need action under NGA section 7(b).

Order No. 636-B, ¶ 61,272, at 62,011.

A group of LDC petitioners[32] challenges the Commission's statement that changes to contract-storage withdrawal and injection schedules do not require a § 7(b) abandonment proceeding. We agree with the petitioners that it is difficult to discern exactly what the Commission's position is on this issue, and we grant the petitioners relief insofar as the Commission stated in Order No. 636-B that any change to injection and withdrawal schedules can be effected without a § 7(b) abandonment proceeding.

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32. The LDC petitioners are the Associated Gas Distributors, the Atlanta Gas Light Company, the Chattanooga Gas Company, the Brooklyn Union Gas Company, Elizabethtown Gas Company, and Long Island Lighting Company.

If the Commission has permitted the pipelines to "abandon" a "service rendered by means of . . . facilities" certificated by the Commission, then it has failed to comply with § 7(b), which requires a "due hearing" and a Commission finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). In general, the test for § 7 abandonment is whether the certificate-holder "permanently reduces a significant portion of a particular service." *Reynolds Metals Co. v. FPC*, 534 F.2d 379, 384 (D.C.Cir.1976); *see also Kansas Power & Light Co. v. FERC*, 851 F.2d 1479, 1481 (D.C.Cir.1988). By comparison, the withholding of gas delivery to an interruptible-transportation customer is not an "abandonment," because the customer has no right to guaranteed delivery under its contract or the certificate of service. *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 129-30 (D.C.Cir.1982). Although the court has reserved the issue whether a § 7(b) abandonment occurs when only the identity of the customer changes, an abandonment does take place "when there is a reduction or alteration in overall service." *Tennessee Gas Pipeline Co. v. FERC*, 972 F.2d 376, 384 (D.C.Cir.1992).

According to the submissions by the Associated Gas Distributors in the administrative record, a customer who contracts for storage is concerned with two elements: capacity (how much gas can be stored) and deliverability (how much gas can be withdrawn on a given day).[33] The AGD attached affidavits

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33. The Commission has defined these terms as follows:

> [I]n contracting for storage, a customer reserves a specific level of deliverability, capacity, and injection/withdrawal services. Deliverability reflects the right of the storage customer to call on the delivery capacity

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from six member LDCs who stated that changes to injection and withdrawal schedules could reduce deliverability, with adverse consequences on their ability to meet residential customers' demands. Elizabethtown Gas Company, in its opposition to CNG's compliance filing in its restructuring proceeding, objected to CNG's specific proposals to reduce withdrawal amounts when contract-storage customers had low gas inventories in storage, to maintain elevated minimum inventory levels during the early winter months, to limit monthly withdrawal amounts to less than the total of the daily amounts, to reduce firm withdrawal rights to best-efforts rights, and to impose minimum inventory turnovers.

It is impossible, on the current record, to determine on a generic basis what changes to injection and withdrawal schedules would "permanently reduce[ ] a significant portion" of contract-storage service. *Reynolds Metals*, 534 F.2d at 384. Because contractual deliverability entitlements are an integral part of the customer's contract-storage rights, modifications that affect those rights could in some instances constitute a § 7 abandonment. On the other hand, under other circumstances an adjustment to an injection or withdrawal schedule could be sufficiently minor or temporary that no abandonment would occur. Whether an abandonment proceeding is necessary depends on the individual customer's storage contract and on the pipeline's proposed modifications, none of which are before us now.

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> of the storage facilities every day for a specified level of daily contract deliverability. Injection/withdrawal is the injection and withdrawal of gas from storage.

Consolidated Gas Transmission Corp., 47 F.E.R.C. ¶ 61,171, at 61,563, *order on reh'g*, 49 F.E.R.C. ¶ 61,041 (1989).

Appendix A

To the extent that the Commission issued in Order No. 636-B a sweeping statement that no modifications to injection and withdrawal schedules for a contract-storage customer require an abandonment proceeding, such a statement is inconsistent with § 7. In its brief, however, the Commission denies that it has taken any such steps to degrade contract-storage rights. Instead, the Commission maintains that it has merely allowed pipelines to propose "necessary and reasonable" changes in the restructuring proceedings, Order No. 636-B, ¶ 61,272, at 62,011, for which the Commission has authority under § 5. In the restructuring proceedings, the Commission has followed this approach, approving proposed modifications to withdrawal and injection schedules if the pipeline can prove that the changes are "necessary and reasonable."[34]

The Commission's theory that it has the authority to proceed in the restructuring proceedings under § 5 rather than in abandonment proceedings under § 7(b) is explained nowhere in the Order No. 636 series. *See* Order No. 636-A, ¶ 30,950, at 30,579; Order No. 636-B, ¶ 61,272, at 62,011. Under § 7(b), the Commission must hold a "due hearing" and must make a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). By contrast, under § 5 the Commission need hold only a "hearing" and must find that an existing contract is "unjust, unreasonable,

34. *See, e.g., Equitrans, Inc.*, 63 F.E.R.C. ¶ 61,009, at 61,064, *order on reh'g*, 64 F.E.R.C. ¶ 61,155, at 62,238, *order on reh'g*, 65 F.E.R.C. ¶ 61,132 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,235 (1994), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C.Cir.); *ANR Pipeline Co.*, 62 F.E.R.C. ¶ 61,079, at 61,527-28, *order on reh'g*, 64 F.E.R.C. ¶ 61,140, at 62,006, *order on reh'g*, 65 F.E.R.C. ¶ 61,162 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,340, *order on reh'g*, 68 F.E.R.C. ¶ 61,009 (1994), *order on reh'g*, 71 F.E.R.C. ¶ 61,033 (1995), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C.Cir.).

unduly discriminatory, or preferential." *Id.* § 717d(a). We need not decide whether compliance with the procedures in § 5 could in certain circumstances satisfy the applicable statutory requirement in § 7(b). The Commission has assured us in its brief that its approach under § 5 will be "consistent" with the § 7 requirements. But without any explanation in the Order No. 636 decisions for why the Commission's procedures satisfy § 7(b), we cannot accept the Commission's suggestion that its exercise of its § 5 authority in the restructuring proceeding would obviate the need for abandonment hearings.

On the other hand, any claim that a particular pipeline's modification to contract-storage withdrawal and injection schedules requires a § 7(b) abandonment proceeding is premature and should be raised, if at all, in the review of individual restructuring proceedings.[35]

3. *Capacity retention by transportation-only pipelines*

A central part of the Commission's unbundling program is the requirement that all pipelines assign to their firm-transportation customers the firm-transportation capacity that the pipelines held on upstream pipelines. 18 C.F.R. § 284.242. Now that customers can buy gas directly from the producers, they may bear the responsibility of reserving capacity both on "upstream" and "downstream" pipelines.[36] If the downstream

35. The LDC petitioners object that the Commission lacked substantial evidence to support the required showing under § 5 that existing contract-storage service was not "just and reasonable." We similarly defer any review of this claim until applied in a concrete situation in a restructuring proceeding.

36. An "upstream" pipeline is located closer to the wellhead, or production area. A "downstream" pipeline is located closer to the burner- tip, or the end-user.

pipeline were allowed to retain the capacity on the upstream pipeline, the Commission reasoned, it would inhibit the formation of a competitive gas-sales market by preventing downstream customers from gaining access to the new opportunity to purchase gas directly from the producers. Order No. 636, ¶ 30,939, at 30,417-18.

Two pipeline petitioners, ANR Pipeline Company and Colorado Interstate Pipeline Company, urge the Commission to carve out an exception for "transportation-only pipelines" — pipelines that do not offer any gas sales. For example, a downstream pipeline may wish to offer a customer a package of firm-transportation capacity on its pipeline as well as on a connecting upstream pipeline; the customer may well prefer not to have to contract separately with the upstream pipeline.

This petition for review has been rendered moot by an intervening declaratory order. In *Texas Eastern Transmission Corp.*, 74 F.E.R.C. ¶ 61,074, at 61,220 (1996), *reh'g pending*, Docket No. CP 95-218, the Commission declared that the successful completion of unbundling under Order No. 636, with the separation of pipelines' merchant and transportation functions, had alleviated the Commission's former concerns that pipelines would obstruct access to production areas to favor their merchant functions. Accordingly, the Commission announced that it would "decide whether to allow pipelines to acquire upstream or downstream capacity on a case-by-case basis." *Id.* The Commission's intervening action appears to have provided the pipeline petitioners with the relief that they had sought; any further relief is available in review of the declaratory-order proceeding.

4. *Eligibility date for no-notice transportation*

In its new regulation, the Commission requires interstate pipelines "that provided a firm sales service on May 18, 1992" to offer no-notice transportation service. 18 C.F.R. § 284.8(a)(4). In Order No. 636-A, the Commission clarified that "[t]he pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no- notice firm, city-gate, sales service on May 18, 1992." Order No. 636-A, ¶ 30,950, at 30,573. Although several commentators requested the Commission to require pipelines to extend no-notice transportation service to customers who had already converted from bundled firm-sales service under Order No. 436 and consequently no longer received such service on May 18, 1992, the Commission denied rehearing. The Commission offered three reasons: first, that it was prudent to begin the experiment with no-notice transportation on a limited basis; second, that customers who were not receiving bundled firm-sales service on May 18, 1992, "were not relying on that service"; and third, that such customers "could not reasonably expect to receive no-notice transportation in the future" because neither Order No. 436 nor the Notice of Proposed Rulemaking for Order No. 636 had contemplated it. Order No. 636-B, ¶ 61,272, at 62,007.

The National Association of Gas Consumers (NAGC) contends that the ineligibility of former bundled firm-sales customers who converted to open- access transportation under Order No. 436 to receive no-notice transportation is unduly discriminatory.[37] NAGC relies on the Commission's own

37. NAGC frames its argument in terms of "small" customers and confuses in its brief the distinct issues of small-customer rates (one-part rates at an imputed load factor) and no-notice transportation service. In fact, the

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regulation, promulgated by Order No. 436, which requires an open-access pipeline to offer service "without undue discrimination." 18 C.F.R. § 284.8(b)(1). And as NAGC points out, the Commission found in Order No. 636 that the pipelines' open-access firm-transportation service under Order No. 436 was unlawfully discriminatory because it did not provide the same quality of transportation service as was available with bundled firm-sales service. Order No. 636, ¶ 30,939, at 30,402. Now, customers who converted under Order No. 436 remain limited to stand-alone firm-transportation service subject to scheduling and balancing requirements and other penalties. Thus, NAGC maintains that the Commission must extend eligibility for no-notice transportation service to customers who converted before Order No. 636 in reliance on the non-discrimination provisions.

We find the Commission's justifications in Order No. 636-B unconvincing. The Commission's desire to proceed cautiously with no-notice transportation, rather than require pipelines to offer it to all customers, cannot explain the disadvantaging of former bundled firm-sales customers who converted under Order No. 436. Although those customers had no right to expect to receive no-notice transportation service under Order No. 636, neither did customers who did receive bundled firm-sales service on May 18, 1992. Finally, the Commission has not provided substantial evidence to support its assumption that bundled firm-

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availability of no-notice transportation service does not depend on a customer's size. NAGC's argument about small-customer rates fails because eligibility for small-customer rates is determined by customer class, so any pipeline that offered small-customer rates on May 18, 1992, must continue to offer such rates "on the same basis" to all customers. Order No. 636-A, ¶ 30,950, at 30,600.

sales customers who retained bundled service relied more heavily on reliability of transportation service than did customers who switched to open-access transportation. We therefore remand this issue to the Commission for further explanation of which customers should be eligible for no-notice transportation service.

B. *Right of First Refusal*

Section 7(b) of the Natural Gas Act prohibits pipelines from abandoning certificated firm-transportation service until the Commission makes a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). In its original adoption of open-access transportation in Order No. 436, the Commission provided automatic "pre-granted abandonment"[38] for all firm-transportation service provided under a Part 284 blanket certificate. 18 C.F.R. § 284.221(d) (1989). After the order was twice vacated on other grounds,[39] the Commission re-promulgated the automatic pre-granted abandonment rule in Order No. 500-H, ¶ 30,867, at 31,583- 85. In its review of Order No. 500-H, the court remanded automatic pre-granted abandonment because "the Commission has not yet adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation — protection of gas customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period." *AGA II*, 912 F.2d at 1518. In *AGA II*, the court concluded that

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38. A natural gas company that receives "pre-granted abandonment" of a certificated service need not undergo the customary § 7 abandonment public convenience and necessity.

39. Order No. 436 was vacated by *AGD I* in 1987. Then Order No. 500 was vacated by *AGA I* in 1989. *See supra* Part I.B.

the Commission's reliance on various market alternatives available to LDCs — namely interruptible transportation, stand-by gas service and gas from alternative suppliers — provided inadequate protection for LDCs. *Id.* at 1517. The court similarly rejected the Commission's contention that it was furthering purposes other than the protection of existing customers because "the Commission's response seems to entail an enormous qualification of its basic purpose." *Id.* On remand from AGA II, the Commission decided to hold the issue of pre-granted abandonment in abeyance until Order No. 636. *See* Order No. 500-J, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,915 (1991).

In Order No. 636, the Commission responded to *AGA II* by amending its regulations to provide that an existing customer of long-term firm- transportation service could avoid pre-granted abandonment if it abided by a new right-of-first-refusal (ROFR) mechanism. 18 C.F.R. § 284.221(d). No petitioner challenges the Commission's rule that interruptible transportation, and firm transportation with a contract term of less than one year, are subject to automatic pre-granted abandonment even without the right of first refusal. Order No. 636, ¶ 30,939, at 30,446; Order No. 636-A, ¶ 30,950, at 30,625-26. But the petitioners do challenge pre-granted abandonment for long-term firm transportation. In essence, the issue is whether the right-of-first-refusal mechanism provides the protection for pipeline customers that *AGA II* requires.

The right-of-first-refusal mechanism consists principally of two matching requirements: rate and contract term. *See* 18 C.F.R. § 284.221(d)(2)(ii). Near the end of a long-term firm-transportation contract, the existing customer may notify the pipeline that it intends to exercise its right of first refusal. The pipeline must post the availability of that capacity on its

electronic bulletin board and, in accordance with the criteria set forth in its tariff, identify the "best bid" offered by any competing shippers. Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. The customer then has the right to match the competing bid's rate, up to the maximum "just and reasonable" rate that the Commission has approved for that service, and the competing bid's contract term. Competing shippers may choose to bid for only a portion of the capacity in the expiring contract. Order No. 636, ¶ 30,939, at 30,451-52; Order No. 636-A, ¶ 30,950, at 30,634- 35. The Commission promised that it would scrutinize competing bids from pipelines' marketing affiliates to ensure that they did not collude to increase the bidding level.[40] Order No. 636, ¶ 30,939, at 30,451; Order No. 636- A, ¶ 30,950, at 30,634.

Originally, the Commission contemplated that competing bids could be for any contract length. According to the Commission, "[o]ther things being equal, the satisfaction of long-term transportation needs should have priority over the satisfaction of shorter-term needs." Order No. 636, ¶ 30,939, at 30,450. In Order No. 636-A, the Commission reconsidered that decision and found

> that capping the contract term that must be matched by a customer exercising its right of first refusal at a period of 20 years strikes an appropriate balance between the pipeline's

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40. The Commission exempted from pre-granted abandonment the firm-transportation capacity of any customer who converted from bundled firm-sales service between February 13, 1991 (the effective date of Order No. 500-J) and May 18, 1992 (the effective date of Order No. 636). 18 C.F.R. § 284.221(d)(3); *see* Order No. 636, ¶ 30,939, at 30,452; Order No. 636-A, ¶ 30,950, at 30,635-36.

> need for stability, the customer's need for flexibility, and the Commission's overall goal in Order No. 636 to foster long- term, market driven arrangements in the gas industry. This cap, in the Commission's judgement, ensures that the customer obtaining the service values the service sufficiently to commit to using it for a reasonable period and provides the pipeline with a reasonable level of stability. Twenty years has been the traditional length of long-term contracts in the natural gas industry and a number of recent contracts for new capacity are for a twenty year term.

Order No. 636-A, ¶ 30,950, at 30,631. Commissioner Moler, dissenting in part, characterized the twenty-year period as "a blatantly anti-LDC rule," given that LDCs typically have existing contractual relationships jeopardized by pre-granted abandonment, and urged the adoption of a shorter contract-term cap. *Id.* at 30,678-79.

1. *Pre-granted abandonment generally*

Many of the petitioners[41] contend that the Commission's pre-granted abandonment of firm-transportation service violates § 7. The petitioners maintain that the right-of-first-refusal

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41. The petitioners on this issue include the Industrial End-User petitioners (the Process Gas Consumers Group, the American Iron and Steel Institute, the Georgia Industrial Group, the American Forest and Paper Association, Arcadian Fertilizer, and the Virginia Electric and Power Company), the American Public Gas Association, the National Association of Gas Consumers, and three LDC petitioners (Atlanta Gas Light Company, Chattanooga Gas Company, and NIPSCO).

mechanism provides inadequate protection to existing pipeline customers from the pipelines' market power.

The Commission may satisfy its § 7 obligations by making generic findings of public convenience and necessity. In *Mobil Oil Exploration & Producing Southeast Inc. v. United Distribution Cos.*, 498 U.S. 211, 227, 111 S.Ct. 615, 625, 112 L.Ed.2d 636 (1991), the Supreme Court upheld a pre-granted abandonment scheme under the Commission's Order No. 451, even though the Commission's "approval is not specific to any single abandonment but is instead general, prospective, and conditional." *See also FPC v. Moss*, 424 U.S. 494, 499-502, 96 S.Ct. 1003, 1007-08, 47 L.Ed.2d 186 (1976). The Court approved the Commission's findings that, under its good- faith negotiation procedures for the pre-granted abandonment of producers' sale of "old gas" under the NGPA to pipelines, pipelines would be protected "by allowing them to buy at market rates elsewhere if contracting producers insisted on the new ceiling price." *Mobil Oil*, 498 U.S. at 227, 111 S.Ct. at 626. In *AGA II*, by contrast, the court held that the Commission had not adequately explained why pre-granted abandonment of firm-transportation in Order No. 500-H would not "allow pipelines indirectly to extract monopoly profits from their customers." 912 F.2d at 1516. Most important, the Commission's proposed alternatives to existing firm-transportation service, such as interruptible transportation and stand-by service, failed to provide the existing customer with an adequate level of protection. *Id.* at 1517. From *Mobil Oil* and *AGA II*, we conclude that, for a finding of public convenience and necessity for pre-granted abandonment under § 7, the Commission must make appropriate findings that existing market conditions and regulatory structures protect customers from pipeline market power.

Appendix A

The Commission's initial protective measures — contractual "evergreen" or "roll-over" clauses — are by themselves inadequate. The Commission allows the pipeline and the customer to negotiate such a contractual provision allowing the parties to extend the contract before termination and thereby avoid the abandonment issue. Moreover, the Commission requires pipelines that offer evergreen or roll-over clauses to do so on a non-discriminatory basis. Order No. 636-A, ¶ 30,950, at 30,628. Yet the Commission declined to mandate the inclusion of contract-extension clauses. *Id.* As the petitioners note, the voluntary nature of evergreen and roll-over clauses means that those pipelines that do enjoy market power will likely refuse to offer such clauses to their customers. Thus, voluntary contract-extension clauses alone do not provide sufficient protection to existing pipeline customers.

The mandatory right-of-first-refusal mechanism, however, provides substantially more protection to existing customers.[42]

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42. The Commission also provided that its

> complaint procedure is always available to remedy an unjustified loss of service. A hearing is necessary, however, only when there are material facts in dispute. As the Commission has explained, the right of first refusal is an adequate protection for LDCs serving core customers.

Order No. 636-A, ¶ 30,950, at 30,633. Although the petitioners object that the complaint process, 18 C.F.R. § 385.206, provides inadequate protection, it is evident that the Commission intended the complaint process to serve only as a back-up to the right-of-first-refusal mechanism. We do not address the petitioners' contention, made for the first time at oral argument, that the Commission should have adopted a complaint procedure modeled after 18

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First, shippers bid against one another for capacity, which in the Commission's view will prevent the pipeline from using the right-of-first-refusal mechanism to push the rate above the competitive market price.[43] Second, under the right-of-first-refusal mechanism the competing bid is capped at the maximum "just and reasonable" rate, which protects the existing shipper from having to match a bid higher than the Commission-approved rate. If the existing customer is willing to pay the maximum approved rate, then the right-of-first-refusal mechanism ensures that the pipeline may not abandon the certificated service. In this way, even a captive customer served by a single pipeline can exercise its right of first refusal and retain its long-term firm-transportation service against rival bidders. Hence, the basic structure of the right-of-first-refusal mechanism provides the protections from pipeline market power required for pre-granted abandonment under § 7.

2. *The twenty-year contract term*

The petitioners also contend that the contract term-matching condition allows pipelines to exercise market power inconsonant

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C.F.R. § 157.106, which allows customers to contest the pre-granted abandonment of optional expedited certificates (an innovation of Order No. 436 in which the Commission presumes that an application for a "new service" meets the public convenience and necessity if the pipeline agrees to bear the full economic risk, *see AGD I*, 824 F.2d at 1030-31).

43. The Commission decided not to specify on a generic basis the appropriate method for pipelines to use in determining the "best bid." *See* Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. Rather, as the Commission stated, it can guard against such pipeline influence in its review of the individual restructuring proceedings and pipeline tariff filings.

with pre-granted abandonment. Thus, on capacity-constrained pipelines existing customers may be forced to match competing bids for twenty years' duration, which would not be the outcome in a competitive market without pipelines' natural monopoly. Competing bidders who come up against the rate ceiling for this scarce resource — capacity on constrained pipelines — may bid up the length of the contract term to try to win the auction. In effect, bidding for a longer contract term becomes a surrogate for bidding beyond the maximum rate level. Especially with the new capacity-release mechanism, a competing bidder could bid for a longer contract term than it would contract for in a competitive market, release the excess capacity at a discount, and absorb the loss just as though it had bid an above-maximum rate for a shorter term.

The Commission acknowledged the reality that contract duration is a measure of value when it declared that its policy was "for the capacity to go to the person who values it the most, as evidenced by its willingness to bid the highest price for the longest reasonable time." Order No. 636-A, ¶ 30,950, at 30,630. As a general matter, in a perfectly competitive market, a long-term contract incorporates a premium for stability, and a pipeline naturally values a longer-term transportation contract more highly, ceteris paribus. Order No. 636, ¶ 30,939, at 30,450. Thus, the contract term-matching condition is a rational means of emulating a competitive market for allocating firm-transportation capacity. There are obvious drawbacks — the industrial petitioners provide the example of a factory owner with a productive asset that has only a short useful life. Order No. 636-A, ¶ 30,950, at 30,629-30. But industrial end-users are also far more likely to have ready access to alternative fuels than do the residential consumers served by LDCs. *See AGD I*, 824 F.2d at 995.

For purposes of pre-granted abandonment, however, the issue is whether the Commission has shown that its choice of a twenty-year term-matching cap protects consumers against the exercise of pipeline market power. The petitioners note that longer-term contracts lock in customers and serve as a barrier to entry into the pipeline market by potential competitors. Rival pipelines will not build extensions to their system if the market for additional capacity has been foreclosed by long-term contracts with the existing pipeline. The Commission responds only that the pipeline plays no role in the competitive bidding process and thus cannot exercise market power. In the Commission's view, its choice of a twenty-year period reflects a reasonable weighing of the relative interests in preventing market constraint and encouraging market stability. None of these explanations, however, supports a finding that the twenty-year term-matching cap adequately protects against pipelines' pre-existing market power, which they enjoy by virtue of natural-monopoly conditions. The Commission has not explained why the twenty- year cap will prevent bidders on capacity-constrained pipelines from using long contract duration as a price surrogate to bid beyond the maximum approved rate, to the detriment of captive customers. If the maximum approved rate artificially limits a rival shipper's ability to outbid the existing shipper, the rival shipper may offer a higher-value contract by bidding up the contract duration instead.[44]

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44. The LDC petitioners also contend that the Commission failed to consider that, following Order No. 636, LDCs are placed in a more vulnerable market situation, in which their traditional customers can purchase gas from marketers. The Commission reasonably responded that LDCs are no different from other industry participants in that they will have to evaluate future risks in determining how much capacity to reserve. Order No. 636-B, ¶ 61,272, at 62,026.

A further concern with the Commission's choice of a twenty-year cap is the Commission's reasoning in selecting twenty years. Most of the commentators before the agency had proposed much shorter contract-term caps, such as five years.[45] The Commission relied on the fact that twenty-year contracts have been "traditional" in the natural-gas industry. Order No. 636-A, ¶ 30,950, at 30,631 n.437. However, numerous commentators on rehearing of Order No. 636-A, as well as Commissioner Moler, *id.* at 30,679, pointed out that twenty-year contracts have been traditional only for contracts involving the construction of new facilities, where the pipeline requires a long-term contract to secure financing for the project, but not for contracts for the continuation of service after contract expiration. Indeed, both of the decisions that the Commission cited for the proposition that twenty-year contracts are customary were for new facilities.[46] Also, renewal contracts appear more similar to the situation in the right-of-first- refusal mechanism. The Commission in its brief responds that the term-matching cap was designed "not to determine the length of typical gas contracts, but to establish a reasonable outer boundary for contract length, within which the ROFR might reasonably

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45. The petitioners contend in part that the twenty-year cap cannot stand because the Commission failed to explain why it rejected the commentators' proposals for a shorter period. When, as here, the Commission must select some, necessarily somewhat arbitrary figure, we will defer to the Commission's expertise if it provides substantial evidence to support its choice and responds to substantial criticisms of that figure.

46. *See Pacific Gas Transmission Co.*, 56 F.E.R.C. ¶ 61,192, at 61,727-28, *order on reh'g*, 57 F.E.R.C. ¶ 61,097 (1991), *order on reh'g*, 62 F.E.R.C. ¶ 61,243 (1993), *petitions for review pending sub nom. Altamont Gas Transmission Co. v. FERC*, No. 91-1369 (D.C.Cir. argued Nov. 14, 1995); *Iroquois Gas Transmission Sys., L.P.*, 53 F.E.R.C. ¶ 61,194, at 61,779-82, 1990 WL 488925 (1990), *order on reh'g*, 54 F.E.R.C. ¶ 61,103 (1991).

function." The petitioners' claim, however, is that because the Commission looked to the wrong type of contract to determine the typical contract length it may have selected an outer boundary that is longer than it would have been if the Commission had examined the duration of renewal contracts. The Commission failed to respond to this objection in the Order No. 636 series.

Both of these reasons — the Commission's failure to explain why the twenty-year cap will protect against pipelines' market power, and the failure to explain why it looked at new-construction contracts in arriving at the twenty-year figure — persuade us to remand the length of the contract term-matching condition to the Commission for further consideration.[47] The right-of-first-refusal mechanism, incorporating the twin matching conditions of rate and contract term, is sufficiently justified. We remand only as to the Commission's reasons for adopting a twenty-year cap.

3. *Requirement to discount*

Petitioner Meridian Oil Inc., joined by the American Public Gas Association, challenges a different aspect of the right-of-first-refusal mechanism. The Commission declared that a

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47. The industrial petitioners also contend that the twenty-year cap is unduly discriminatory under § 5 of the NGA because industrial end-users are more likely to have shorter-term natural gas needs than other customers, such as LDCs who can count on still having residential customers twenty years in the future. The Commission responded that "[t]he requirement is not unduly discriminatory" because "[a]ll parties have an equal opportunity to bid for the capacity." Order No. 636-A, ¶ 30,950, at 30,632. Although the twenty-year cap may affect different classes of customers differently, under these circumstances it does not violate § 5.

pipeline need not accept a competing bid for a rate less than the maximum approved rate; in other words, "pipelines are not required to discount under the rule." Order No. 636-A, ¶ 30,950, at 30,629. The result is that a pipeline can choose between providing service to the highest bidder at a discounted rate and not providing service at all unless a shipper is willing to pay the maximum approved rate. In its comments to the Commission, Meridian urged that pipelines be required to accept the "best bid," which on pipelines on which capacity was not constrained would likely be less than the maximum approved rate. The Commission responded that it would

> not require pipelines to discount transportation rates. However, if a pipeline fails to attempt to maximize throughput, there is no guarantee that it will be able to recover all the costs of its underutilized capacity from its firm customers when it files its next rate case. Evidence that a pipeline refused to accept the highest valued bid for capacity below the maximum rate will be given significant weight during its next rate case.

Order No. 636-B, ¶ 61,272, at 62,028 (footnote omitted).

Meridian contends first that the Commission violated § 7(b) by discount. In Meridian's view, by forcing the existing customer to pay the maximum approved rate to ensure continuity of service, even if the competitive outcome as determined by the bidding process is a below-maximum rate, the Commission has failed to protect customers against pipelines' market power. *See Mobil Oil*, 498 U.S. at 227, 111 S.Ct. at 625; *AGA II*, 912 F.2d at 1517. However, as we held above, the Commission has already

protected against pipelines' market power by removing the pipeline's ability to influence the bidding and by limiting the maximum rate that the pipeline may charge. *See* supra at 76. The Commission first authorized selective discounting by pipelines providing transportation under a Part 284 blanket certificate in Order No. 436, ¶ 30,665, at 31,540-48. *See* 18 C.F.R. § 284.7(d)(5); *AGD I*, 824 F.2d at 1007-13; *see also Mississippi Valley Gas Co.*, 68 F.3d at 507. Given that the purpose of selective discounting is to increase throughput by allowing pipelines to engage in price discrimination in favor of demand-elastic customers, *AGD I*, 824 F.2d at 1011, Meridian's proposal that pipelines be required to discount in favor of demand-inelastic, captive customers would render meaningless pipelines' ability to charge up to the maximum approved rate. The § 7(b) abandonment provisions protect customers against loss of service only if the customer is willing to pay the maximum rate approved in a rate proceeding.

Meridian's second contention is that the Commission acted in an arbitrary and capricious manner by not responding to Meridian's comments that the lack of a requirement to discount would prevent the right-of-first-refusal mechanism from reflecting competitive market forces on pipelines with excess capacity. The Commission responded to Meridian's objection by assuring that a pipeline is not entitled to full cost recovery in its next rate proceeding when it forgoes the opportunity to recover some of its fixed costs from a bid rate between the minimum and maximum filed rates.[48] Order No. 636-B, ¶ 61,272,

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48. Because we are satisfied by the Commission's assurance that it will examine pipelines' failure to discount in rate proceedings, we need not address the Commission's alternative contention in its brief that requiring pipelines to discount would violate the Commission's duty to ensure adequate capitalization to pipelines.

at 62,028. Meridian has offered no reason why the Commission's rate scrutiny will not provide sufficient incentives for pipelines to discount in appropriate circumstances. Accordingly, we affirm the Commission's decision not to require pipelines to discount in the right-of-first-refusal process.

C. *Curtailment*

When supply shortages arose in the natural gas industry during the 1970s, the Commission adopted end-use curtailment plans to protect high-priority customers from an interruption of supply. *See generally Consolidated Edison Co. v. FERC*, 676 F.2d 763, 765-67 (D.C.Cir.1982); *North Carolina v. FERC*, 584 F.2d 1003, 1006-08 (D.C.Cir.1978). In 1973, the Commission found itself " 'impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation of this wasting resource.' " Order No. 467, 49 F.P.C. 85, 86 (quoting *Arkansas Louisiana Gas Co.*, 49 F.P.C. 53, 66 (1973)), *order on reh'g*, 49 F.P.C. 217, *order on reh'g*, 49 F.P.C. 583 (1973), *petitions for review dismissed sub nom. Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33 (D.C.Cir.1974). The Commission's end-use curtailment schemes were essentially enacted into law by title IV of the Natural Gas Policy Act of 1978 (NGPA),[49] which establishes the following priority system:

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49. Section 401(a) provides that:

> "[T]he Secretary of Energy shall prescribe and make effective a rule, . . . which provides that, . . . to the maximum extent practicable, no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any essential

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> Whenever there is an insufficient supply, under the Act first in line to receive gas are schools, small business, residences, hospitals, and all others for whom a curtailment of natural gas could endanger life, health, or the maintenance of physical property. After these "high-priority" users have been satisfied, next in line are those who will put the gas to "essential agricultural uses," followed by those who will use the gas for "essential industrial process or feedstock uses," followed by everyone else.

Process Gas Consumers Group v. United States Dep't of Agric., 657 F.2d 459, 460 (D.C.Cir.1981) (*Process Gas I*); *see also* 18 C.F.R. §§ 281.201-281.215 (the Commission's regulations implementing NGPA § 401).

With the introduction of stand-alone firm-transportation service in Order No. 436, the Commission distinguished for the first time between supply curtailment and capacity curtailment. Transportation service can suffer from a capacity interruption (such as a force majeure loss of capacity due to pipeline system failure or a pipeline's overbooking of capacity), whereas sales service can suffer from a shortage in the supply of gas. *See* Order No. 436, ¶ 30,665, at 31,515; Order No. 436-A, ¶ 30,675, at

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> agricultural use, unless such curtailment . . . (2) is necessary in order to meet the requirements of high priority users."

15 U.S.C. § 3391(a); *see also id.* § 401(f)(2), 15 U.S.C. § 3391(f)(2) (defining "high-priority user").

31,652. The Commission's subsequent approach was to allow pipelines to adopt pro rata capacity curtailment (allocation proportional to the amount reserved, without regard to end use), *see, e.g., Texas Eastern Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,692-93, 1986 WL 215099 (1986), *order on reh'g*, 41 F.E.R.C. ¶ 61,015 (1987), *aff'd sub nom. Texaco, Inc. v. FERC*, 886 F.2d 749 (5th Cir.1989), unless the parties agreed to end-use capacity curtailment on a particular pipeline, *see, e.g., Florida Gas Transmission Co.*, 51 F.E.R.C. ¶ 61,309, at 62,010-11, *order on reh'g*, 53 F.E.R.C. ¶ 61,396 (1990).

In *City of Mesa v. FERC*, 993 F.2d 888 (D.C.Cir.1993), the court reviewed a proceeding in which the Commission had approved end-use curtailment for supply shortages but pro rata curtailment for capacity interruption. *El Paso Natural Gas Co.*, 54 F.E.R.C. ¶ 61,316, at 61,928-29, order on reh'g, 56 F.E.R.C. ¶ 61,290, at 62,153-54 (1991). First, the court upheld the Commission's interpretation of the word "deliveries" in § 401(a) of the NGPA to refer only to pipelines' sale of gas, so that the statutory end-use curtailment scheme in title IV applied only to supply curtailment. 993 F.2d at 892-94; *see also Atlanta Gas Light Co. v. FERC*, 756 F.2d 191, 196-97 (D.C.Cir.1985). The court found that different treatment of supply and capacity curtailment was reasonable because high-priority users can "generally 'fend for themselves' " to protect against capacity interruption:

> Supply shortages usually lead to prolonged periods in which there is simply too little gas to serve the needs of all users. In contrast, capacity constraints occur when there is enough gas in the market but an unexpected event has caused a brief interruption in the

> movement of the gas to consumers. Additionally, capacity constraints, unlike supply shortages, may only affect the movement of gas on part of a pipeline, thereby allowing customers to receive their quota of gas by using alternate routes that skirt the pipeline bottleneck. These differences mean that pipeline customers can more easily adopt self-help measures to protect their high-priority end-users against the harmful effects of capacity curtailments than supply shortages.

City of Mesa, 993 F.2d at 894-95.

Although City of Mesa upheld the limitation of title IV of the NGPA to supply shortages, the court acknowledged that the NGA provided protections for capacity shortages. The court stated that "implicit in th[e] consumer protection mandate [of NGA §§ 4 and 7(e)] is a duty to assure that consumers, especially high-priority consumers, have continuous access to needed supplies of natural gas." 993 F.2d at 895. This duty arises because " '[n]o single factor in the Commission's duty to protect the public can be more important to the public than the continuity of service provided.' " *Id.* (quoting *Sunray Mid-Continent Oil Co. v. FPC*, 239 F.2d 97, 101 (10th Cir.1956), *rev'd on other grounds*, 353 U.S. 944, 77 S.Ct. 792, 1 L.Ed.2d 794 (1957)). The court emphasized that "since the NGA gives the FERC no specific guidance as to how to apply its broad mandates in a particular case, our review of the FERC's actions here is, again, quite limited." *Id.* In *City of Mesa*, the court concluded that the Commission had failed to engage in reasoned decision making when it approved a curtailment plan that protected "most" high-

priority users rather than all such users. *Id.* at 896-97. The court noted that in Order No. 636-A the Commission had held that "self-help strategies were generally sufficient to assure protection of end-users and thus to meet NGA mandates" but did not further examine whether self-help measures were adequate to protect against capacity curtailment. *Id.* at 897.

In Order No. 636, which was issued before the court's decision in City of Mesa, the Commission continued without change its curtailment policies since Order No. 436. First, the Commission acknowledged that, as a policy matter, it chafed at the title IV end-use curtailment scheme for supply shortages but stated that it was bound by the statute. Order No. 636, ¶ 30,939, at 30,430; *see also Transcontinental Gas Pipe Line Corp.*, 57 F.E.R.C. ¶ 61,345, at 62,117 (1991). The Commission reiterated its reading of § 401(a) that limited its scope to pipelines' sale of gas. Order No. 636- A, ¶ 30,950, at 30,586-89. Second, the Commission maintained that self-help measures would allow the consumer-protection mandate of the NGA to be satisfied by pro rata capacity curtailment:

> The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's [sic] and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers,

> storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (e.g., local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options.

Id. at 30,590.

The Commission's curtailment policies are challenged from both sides. Elizabethtown Gas Company contends that the Commission should have adopted pro rata curtailment for shortages in the supply of pipeline gas, and a group of small distributors contends that the Commission should have adopted end-use curtailment for capacity interruption and for shortages in the supply of third- party gas.

1. *Supply curtailment of pipeline gas*

Elizabethtown contends that because § 402(a) of the NGPA requires end-use curtailment only "to the maximum extent practicable," 15 U.S.C. § 3392(a), the declining role of pipelines as gas merchants renders end-use curtailment for shortages of pipeline gas no longer "practicable." The court recently rejected this argument, made by the same petitioner, in *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866 (D.C.Cir.1993) (*Elizabethtown III*):

> This argument makes no sense to us. Even if [the pipeline] supplies a smaller share of the gas bought by each of the LDCs, the gas it does deliver to them could still in times of

> shortage go first to "high-priority users." Accordingly, it seems entirely "practicable" to increase the level of protection for high priority users above that provided by the pro rata plan.

Id. at 874; *see also Process Gas Consumers Group v. United States*, 694 F.2d 778, 787-92 (D.C.Cir.1982) (*en banc*) (*Process Gas II*) (holding that the phrase "to the maximum extent practicable" gives the Commission broad powers). Although Elizabethtown contends that the near- elimination of pipelines as gas merchants following Order No. 636 requires us to reconsider our holding in Elizabethtown III, this change in the industry does not affect our reasoning that end-use curtailment remains "practicable" no matter how small the pipelines' share of the gas-sales market. The Commission recognized that the limitation of title IV of the NGPA to pipelines' sale of gas means that pipelines are disadvantaged vis-a-vis other gas merchants, but explained that it remained bound by the statute. Order No. 636, ¶ 30,929, at 30,430. Because we have already decided this question in Elizabethtown III, we affirm the Commission's decision that title IV of the NGPA mandates end-use curtailment for shortages in the supply of pipeline gas.

Elizabethtown also maintains that the Commission acted arbitrarily in not requiring high-priority users to compensate pipeline customers who lose gas supply under end-use curtailment. In Elizabethtown III, the court "held that a compensation provision is not necessarily inconsistent with § 401(a)." 10 F.3d at 875. Indeed, this court has long held that the Commission retains the authority under title IV of the NGPA to adopt a compensation scheme. *See Consolidated Edison Co. v. FERC*, 676 F.2d 763, 767 (D.C.Cir.1982); *cf. Elizabethtown*

Gas Co. v. FERC, 575 F.2d 885, 887-89 (D.C.Cir.1978) (*Elizabethtown I*) (holding that the Commission has authority under the NGA to adopt a curtailment compensation plan). In *Elizabethtown III*, the court remanded with instructions for the Commission to consider Elizabethtown's "request for a curtailment compensation scheme." *Id.* In the Order No. 636 series, decided before the court's decision in Elizabethtown III, the Commission stated that its

> position on curtailment compensation plans is that the parties in the individual restructuring proceedings must explore the development of such schemes . . . in the context of developing their individual curtailment plans and in the development of voluntary emergency contractual arrangements between shippers. However, the Commission believes that it would be contrary to the concept of the restructuring proceeding process and the negotiation and development of individually tailored curtailment allocation procedures and emergency mechanisms for it to mandate a generic compensation scheme.

Order No. 636-A, ¶ 30,950, at 30,592; *see also* Order No. 636, ¶ 30,929, at 30,430. The comments by the Commission in the Order No. 636 series continue the Commission's pattern of avoiding the question of curtailment compensation and do not exhibit the reasoned consideration of curtailment compensation that the court subsequently requested in Elizabethtown III.

The Commission has reconsidered the issue of curtailment

compensation, however, on remand from Elizabethtown III. *See Transcontinental Pipe Line Corp.*, 72 F.E.R.C. ¶ 61,037, reh'g denied, 73 F.E.R.C. ¶ 61,357 (1995). In those proceedings, the Commission

> conclude[d] that compensation is needed to render Transco's gas supply curtailment plan just and reasonable. The priority curtailment plan affects the contractual rights of Transco's customers by altering the pro rata allocation of curtailed supplies so that higher priority customers can obtain gas that would otherwise go to lower priority customers.

72 F.E.R.C. ¶ 61,037, at 61,235. The Commission rejected Elizabethtown's proposed compensation scheme, however, in favor of requiring the higher-priority customer to pay: (1) 150% of the spot market price for gas if the lower-priority customer was unable to cover (locate replacement gas on the spot market), or (2) the difference between the cover price and the original contract price if the lower-priority customer was able to cover. *Id.* at 61,237-38.

In light of the Commission's *Transcontinental* decision, the issue of curtailment compensation is not ripe for review. The Commission enjoys broad discretion whether to adopt a compensation scheme on a generic basis or in pipeline-specific proceedings. *See Mobil Oil*, 498 U.S. at 230, 111 S.Ct. at 627. If Elizabethtown remains aggrieved by the Commission's decision to accept its general argument but fashion a different compensation mechanism, then it may seek relief in review of the *Transcontinental* decision. We therefore express no opinion on the appropriateness of any particular curtailment compensation plan.

2. *Capacity curtailment*

The small distributor petitioner group, on the other hand, contends that pro rata capacity curtailment violates the consumer-protection mandate of the NGA. We review the Commission's policy on pro rata curtailment to determine whether it is "just and reasonable" under § 4 and whether it serves the "present or future public convenience and necessity" under § 7(e). *See City of Mesa*, 993 F.2d at 895. The Commission decided that the consumer-protection mandate of the NGA did not require it to adopt end-use capacity curtailment across the board and promised to address the issue in each pipeline restructuring proceeding. Order No. 636-A, ¶ 30,950, at 30,591-92. Indeed, the Commission has broad latitude on whether to effectuate its policies in generic rulemakings or in individual-pipeline adjudications. *Mobil Oil*, 498 U.S. at 230, 111 S.Ct. at 627. The issue presented to us, then, is whether the Commission's decision that the NGA does not require end-use curtailment in all circumstances is " 'reasoned, principled, and based upon the record.' " *Great Lakes Gas Transmission Ltd. Partnership v. FERC*, 984 F.2d 426, 432 (D.C.Cir.1993) (quoting *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578, 593 (D.C.Cir.1979)).

The Commission explained that Order No. 636 had allowed the development of market structures that would enable customers to take independent, market-based steps to avoid the need for Commission-mandated end-use curtailment. Order No. 636-A, ¶ 30,950, at 30,590. Moreover, the Commission found that since the enactment of the NGPA in 1978 "the industry has not experienced shortages beyond isolated, short-lived dislocation," *id.* at 30,591, and "gas has always flowed according to the dictate of the market, *i.e.*, to the heat sensitive users who

need it most and who are thus willing to pay the prevailing market price for it." *Id.* at 30,592. This experience with the industry provides substantial evidence for the Commission's conclusion that end-use curtailment is not required in all circumstances.

We are unpersuaded, particularly in light of the Commission's own actions in the restructuring proceedings, that pro rata capacity curtailment would adequately protect all high-priority customers on all pipelines. *Cf. City of Mesa*, 993 F.2d at 896-97. The Commission's market-based alternatives for customers to avoid curtailment fall into the following categories: (1) arrangements with other pipelines; (2) arrangements with other gas sellers; (3) arrangements for gas storage; (4) arrangements with other customers (including the capacity-release mechanism); and (5) "peak shaving."[50] First, arrangements with other pipelines are more widely available after Order No. 636, such as by using different pipelines that connect to one "market center," but a capacity constraint on a pipeline will still cut off delivery to any "captive customers," no matter how many transportation options some other customers may have. Second, arrangements with other gas sellers are by definition relevant only to supply curtailment, not to capacity curtailment. Third, arrangements for gas storage are unhelpful if the capacity interruption occurs at a point between the contract-storage area and the customer's receipt point. Fourth, obtaining gas from other customers, whether through the capacity-release mechanism or otherwise, depends upon the willingness of lower-priority customers to forgo deliveries. Fifth, practices such as "peak shaving" (letting a little gas go a longer

50. Peak shaving is "the practice of adding propane air mixtures to augment supplies of natural gas during periods of peak demand." *Atlanta Gas Light*, 756 F.2d at 195 n. 5.

way) can temporarily help to alleviate curtailment problems but cannot ensure continuous service if the interruption lasts too long. None of these market-based solutions, therefore, can guarantee continuous service to all high-priority customers in cases of capacity interruptions. Many of the market-based solutions fail to acknowledge that many customers have far less control over access to pipeline capacity than they do over gas supply. In addition, some of the self-help mechanisms will be more readily available to larger pipeline customers. *City of Mesa*, 993 F.2d at 897 n. 7.

Yet the Commission has not applied Order No. 636 in the restructuring proceedings to preclude the development of curtailment plans that provide more protection to higher-priority users. For example, on remand from *City of Mesa*, the Commission reiterated its general policy that "customers can, and should, avail themselves of self-help methods to obtain their needed supplies" but, in light of the decision in *City of Mesa*, ordered El Paso to "includ[e] provisions giving relief to any high priority shipper when that shipper has exercised all other self-help remedies in times of bona fide emergencies." *El Paso Natural Gas Co.*, 69 F.E.R.C. ¶ 61,164, at 61,624 (1994), *order on reh'g*, 72 F.E.R.C. ¶ 61,042, *reh'g denied*, 73 F.E.R.C. ¶ 61,074 (1995). In another restructuring proceeding, the Commission approved a settlement and found its curtailment plan consistent with *City of Mesa* because it "provides an exemption from pro rata curtailment whenever necessary to avoid irreparable injury to life or property." *Florida Gas Transmission Co.*, 70 F.E.R.C. ¶ 61,017, at 61,061 (1995). On occasions, the Commission has suggested that "there may be extraordinary circumstances when reasonable self-help efforts are insufficient, even for large customers," such that some emergency protections may always be required for certain force

majeure capacity interruptions. *El Paso*, 69 F.E.R.C. ¶ 61,164, at 61,624; *see also United Gas Pipe Line Co.*, 65 F.E.R.C. ¶ 61,006, at 61,092, *reh'g denied sub nom. Koch Gateway Pipeline Co.*, 65 F.E.R.C. ¶ 61,338, at 62,630-31 (1993).

We need not reach the issue whether the adoption of a pure pro rata capacity-curtailment scheme on a generic basis would comply with the Commission's duty under the NGA to ensure that "high-priority consumers[ ] have continuous access to needed supplies of natural gas." *City of Mesa*, 993 F.2d at 895. All the Commission did in Order No. 636 was to decide not to require end-use capacity curtailment for all pipelines. Because the Commission expressly declared that it would re-examine the suitability of pure pro rata capacity curtailment for customers on each pipeline, Order No. 636-A, ¶ 30,950, at 30,591-92, we construe any indications that pro rata curtailment will be the default as unreviewable policy statements under § 4(b)(A) of the Administrative Procedure Act, 5 U.S.C. § 553(b)(A). *See Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33, 39 (D.C.Cir.1974). The manner in which the Commission has applied its curtailment policy in the restructuring proceedings supports our conclusion that any preference for pro rata schemes is not suitable for review. *See Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682-83 (D.C.Cir.1991). Accordingly, the compliance of specific curtailment plans with the NGA's consumer-protection mandate remains open on review of the restructuring proceedings.

We uphold the Commission's decision not to require end-use curtailment on a generic basis for capacity curtailment but to proceed instead on a case-by-case basis.

3. *Supply curtailment of third-party gas*

Finally, the small distributor petitioners contend that the consumer-protection mandate of the NGA requires the Commission to adopt end-use curtailment for shortages in the supply of third-party gas. The petitioners concede that title IV of the NGPA applies only to pipelines' sale of gas, but urge that §§ 4 and 7(e) of the NGA require some form of end-use curtailment for the sale of gas by producers and other third parties. The Commission declined to "impos[e] . . . the industry-wide, end-use supply curtailment scheme envisioned by the petitioners" because "the best protection against, and remedy for, supply shortages [i]s to allow the market to establish the price for gas." Order No. 636-A, ¶ 30,950, at 30,591.

As an initial matter, a group of intervenors in support of the Commission maintains that the Commission lacks jurisdiction under § 1(b) to enact a curtailment plan for third-party gas. But the Supreme Court has held expressly that "curtailment plans are aspects of [the Commission's] 'transportation' and not its 'sales' jurisdiction." *Louisiana Power & Light*, 406 U.S. at 641, 92 S.Ct. at 1839 (citing *Panhandle Eastern Pipe Line Co. v. Public Serv. Comm'n*, 332 U.S. 507, 523, 68 S.Ct. 190, 198, 92 L.Ed. 128 (1947)). The intervenors rely on a Fifth Circuit case, *Sebring Utilities Commission v. FERC*, 591 F.2d 1003 (5th Cir.), *cert. denied*, 444 U.S. 879, 100 S.Ct. 167, 62 L.Ed.2d 109 (1979), in which the court indicated that the Commission would not have jurisdiction to order curtailment of gas not owned by a statutory "natural-gas company." *Id.* at 1016-19. However, the ownership of the gas is not relevant to the Commission's transportation jurisdiction because in adopting a curtailment scheme the Commission exercises its jurisdiction over the pipeline, which incorporates

any curtailment plan into its tariff.[51] If we were to follow *Sebring*, then the Commission would also lack jurisdiction to regulate capacity curtailment of third-party gas — a proposition implicitly rejected by the *City of Mesa* court, which in remanding on the capacity-curtailment issue assumed that the Commission had jurisdiction over curtailment plans for third-party gas. 993 F.2d at 895-98. Moreover, *Sebring* was decided before the unbundling of sales from transportation, at a time when virtually all gas was pipeline-owned.[52] Under the principles of Louisiana Power & Light, the Commission's transportation jurisdiction extends to supply curtailment of third-party gas.

The Commission decided that an end-use supply curtailment plan for third-party gas was not required to ensure high-priority customers "continuous access to needed supplies of natural gas." *City of Mesa*, 993 F.2d at 895. As discussed with respect to capacity curtailment, *see supra* at 83-84, the Commission

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51. Our reasons for holding that the Commission may apply a curtailment plan to shortages in the supply of gas owned by someone not a "natural-gas company" are the same as our reasons, for holding that the Commission may apply a capacity-release plan to capacity rights held by a municipal LDC, which is not a "natural-gas company." *See infra* Part III.B.3.

52. The intervenors also rely on *American Public Gas Association v. FERC*, 587 F.2d 1089 (D.C.Cir.1978) (per curiam), in which the court approved the Commission's policy at that time of excluding "direct sales" gas (gas sold directly from producers to LDCs or certain high-priority end-users) from pipelines' end-use curtailment plans, so as to alleviate the shortage of gas in the interstate market. *Id.* at 1097-98. Nothing in that opinion, however, limits the Commission's § 1(b) transportation jurisdiction to pipeline-owned gas or precludes the Commission from adopting a different policy for the curtailment of third-party gas, given the changed circumstances in the end of the gas shortage and the unbundling of sales and transportation. *See* Order No. 636-A, ¶ 30,950, at 30,589-90.

provided a list of market-based alternatives to secure the continuous supply of gas that is convincing in the context of supply curtailment. Although the petitioners posit a force majeure supply shortage that the market-based protections would not cover, namely a "freeze-off" of wells that would prevent all producers from producing sufficient quantities of gas during cold weather, the petitioners have provided no evidence that such an event has ever occurred or is likely to occur in the future. The Commission's decision that such an occurrence is unlikely "given foreseeable supply conditions" is reasonable. Order No. 636-A, ¶ 30,950, at 30,591. In addition, the Commission noted that title III of the NGPA, 15 U.S.C. §§ 3361-3364, authorizes the President to "declare a natural gas supply emergency" in the event of "a severe natural gas shortage, endangering the supply of natural gas for high-priority uses." *Id.* § 3361(a); *see* Order No. 636-A, ¶ 30,950, at 30,591.

Thus, the Commission has complied with the continuity-of-service guarantee of the NGA, as articulated in *City of Mesa*, with respect to supply shortages of third-party gas.

III. Capacity Release

In this part of the opinion, we address challenges to the voluntary capacity release provisions of Order No. 636, which permit holders of firm transportation rights on a gas pipeline to resell them. 18 C.F.R. § 284.243 (1995).[53] Petitioners challenge the Commission's jurisdiction to institute its capacity release program generally, as well as its jurisdiction over (1) LDCs' capacity sales to their local end-users; (2) capacity sales by municipal LDCs; and (3) state-regulated "buy/sell" transactions.

53. Our review is confined to the the capacity release provisions before they were amended by Order No. 577. *See supra* at 64 n. 18.

Petitioners also challenge the exclusion of individually certificated shippers from the capacity release program, the standards that FERC promulgated for determining the prevailing bidder in the capacity release transaction, and the mechanism for crediting interruptible transportation revenues. We conclude that each of petitioners' claims is either incorrect on the merits or is not suited for review in these proceedings.

A. *Introduction*

Among the central goals of Order Nos. 436 and 636 has been the conversion of bundled sales arrangements into separate transportation and gas sales transactions. On the transportation side, the Commission recognized that while much of the nation's interstate pipeline capacity was reserved for firm transportation, those transportation rights ultimately were not being utilized. *See supra* Part I.C. FERC therefore sought to develop an active "secondary transportation market," with holders of unutilized firm capacity rights reselling them in competition with any capacity offered directly by the pipeline.[54] According to the Commission:

> Capacity reallocation will promote efficient load management by the pipeline and its customers and, therefore, efficient use of the pipeline capacity on a firm basis throughout the year. Because more buyers will be able to reach more sellers through firm transportation capacity, capacity reallocation comports with

54. In this sense, the Commission's description of capacity release as creating a secondary transportation market is somewhat misleading, given that both resales of firm capacity and initial sales by pipelines are in direct competition with each other, and unavailable in any other forum.

> the goal of improving nondiscriminatory, open-access transportation to maximize the benefits of the decontrol of natural gas at the wellhead and in the field.

Order No. 636, ¶ 30,939, at 30,418. Understanding petitioners' challenges to the capacity release program requires a brief review of related policies that the Commission has employed in the past to accomplish a similar end.

If a firm capacity holder does not ship gas under its transportation right, it pays the pipeline a "reservation fee," but does not pay a "usage fee." Historically, FERC prohibited such holders of unutilized firm capacity rights from transferring those rights to other shippers, and shippers were therefore able to purchase capacity rights only directly from pipelines. *See generally United Gas Pipe Line Co.*, 46 F.E.R.C. ¶ 61,060 (1989) (approving first experimental capacity brokering program). Beginning with the *Texas Eastern Transmission Corp.* proceedings, 48 F.E.R.C. ¶ 61,248, *order on reh'g*, 48 F.E.R.C. ¶ 61,378 (1989), *order on reh'g*, 51 F.E.R.C. ¶ 51,170, *order on reh'g*, 52 F.E.R.C. ¶ 61,273 (1990), however, the Commission authorized shippers on some pipelines to engage in nondiscriminatory "capacity brokering." Brokering arrangements allowed a holder of firm capacity rights (the "releasing shipper") to sell those rights to a "replacement shipper." The transaction took place directly between the two parties, and the replacement shipper essentially stepped into the shoes of the releasing shipper.

Three years later, in the Order No. 636 and companion *Algonquin Gas Transmission Corp.* proceedings, 59 F.E.R.C. ¶ 61,032 (1992), FERC concluded that it could not ensure that

the extant capacity brokering programs were operating in a nondiscriminatory manner. When transactions occurred directly and privately between shippers, there was no way to verify that certain purchasers were not being favored unreasonably over others. "Simply put, there [were] too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering. . . ." Order No. 636, ¶ 30,939, at 30,416. In FERC's view, fairness could be secured only if capacity resale transactions were both centralized on each pipeline and subject to open bidding. Moreover, uniformity among the various pipelines was necessary to "prevent any pipeline or firm shipper from achieving an undue advantage, or incurring an undue disadvantage, compared to firm shippers on other pipelines." *Id.*

Accordingly, in Order No. 636, the Commission instituted a uniform national "capacity release" program, and exercised its power under NGA § 5 to conform pipelines' existing capacity brokering certificates to that program.[55] *Id.* While both capacity brokering and capacity release arrangements involve the releasing shipper's decision to sell excess capacity, capacity release requires the central involvement of the pipeline in the transaction. Specifically, under capacity release, each interstate pipeline is required to establish and administer an electronic bulletin board ("EBB"), which is a computer through which putative releasing and replacement shippers may communicate.

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55. Capacity brokering agreements already in effect on the date that the pipeline implemented its capacity release program were not substantially altered by Order No. 636. Order No. 636, ¶ 30,939, at 30,421. The Order required that the pipeline enter into a contract directly with the replacement shipper, as it would under capacity release, with terms that mirrored those in the capacity brokering agreement. *Algonquin Gas Trans. Co.*, 59 F.E.R.C. ¶ 61,032, at 61,096-97.

Id. at 30,418. The EBB carries information about available and consummated capacity release transactions. For example, holders of excess firm capacity rights may "post" their available capacity on the EBB. Further, they may establish nondiscriminatory conditions on the sale, including a minimum price and any terms under which the release may continue.[56] Pipelines are also required to post on the EBB any firm capacity that they have available for sale, where the capacity competes for buyers against capacity made available for resale by shippers. "Potential purchasers of capacity will then be able to choose from among the pipeline and the releasers the service that best suits their needs." *Id.* at 30,419. In addition, shippers that wish to acquire firm capacity rights may post offers to purchase capacity on the EBB. 18 C.F.R. § 284.243(d); Order No.636-A, ¶ 30,950, at 30,565.

With two exceptions, the pipeline must sell the capacity to the highest bidder. First, "short-term transactions," *i.e.*, those for capacity releases of less than one month,[57] may be arranged between shippers without competitive bidding.[58] 18 C.F.R. § 284.243(h)(1); Order No. 636-A, ¶ 30,950, at 30,554. Second,

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56. For example, the releasing shipper may elect to release capacity only for so long as the temperature remains above a certain level. If the temperature were to drop, the firm capacity rights would revert to the releasing shipper. Order No. 636, ¶ 30,939, at 30,418.

57. FERC has amended the short-term transactions provision specifically to encompass those capacity releases of no more than 31 days. *See supra* at 64 n. 18. That amendment does not affect our review.

58. The transaction must still be posted on the EBB. In addition, extensions and roll-overs of "short-term" transactions are prohibited. 18 C.F.R. § 284.243(h)(2); Order No. 636, ¶ 30,939, at 30,551.

a releasing shipper may identify a replacement shipper on its own and enter into a "pre-arranged" deal. 18 C.F.R. § 284.243(b); Order No. 636, ¶ 30,939, at 30,418. In such a transaction, the selected replacement shipper need only match — rather than outbid — the highest offer made by any other shipper. 18 C.F.R. § 284.243(e). The net effect is that a shipper may ensure that it will receive certain capacity by entering into a pre-arranged deal that both conforms to the releasing shipper's conditions and matches the maximum allowable rate for the capacity. No matter what form the capacity release transaction takes, however, the purchase price for released capacity may not exceed the maximum rate set by FERC for the capacity. 18 C.F.R. § 284.243(e); Order No. 636, ¶ 30,939, at 30,420.

After the replacement shipper has been identified, the pipeline enters into a contract with it for firm capacity rights.[59] The pipeline then may elect to excuse completely the releasing shipper's obligation to pay the reservation fee and related costs. Order No. 636, ¶ 30,939, at 30,419. Otherwise, the releasing shipper is credited for those costs unless the replacement shipper defaults. 18 C.F.R. § 284.243(f); Order No. 636- A, ¶ 30,950, at 30,553. In no instance, however, is the releasing shipper liable for costs associated with the replacement shipper's transportation of gas.

We now turn to petitioners' varied challenges to the Commission's capacity release program.

B. *Jurisdictional Challenges*

Various petitioners challenge both FERC's jurisdiction to

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59. Order No. 636 pre-granted shippers a limited blanket certificate under NGA § 7 to release capacity in a nondiscriminatory manner.

institute a uniform capacity release program and its jurisdiction over specific transactions and entities. We begin, then, by outlining the Commission's jurisdiction under § 1(b) of the Natural Gas Act of 1938. Ultimately, we conclude that FERC's capacity release program is a legitimate exercise of its jurisdiction over the interstate transportation of natural gas.

In the early part of this century, state regulatory agencies actively involved themselves in structuring the natural gas industry. The Supreme Court, however, severely cabined those efforts in a series of decisions that interpreted the dormant Commerce Clause to preclude state regulation of both the interstate transportation of natural gas and its ensuing sale in wholesale markets.[60] Congress enacted the Natural Gas Act of 1938 to fill the resulting regulatory gap. The Act, as provided in § 1(b), applies

> [1] to the transportation of natural gas in interstate commerce, [2] to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and [3] to natural-gas companies engaged in such transportation or sale, but [does] not apply [4] to any other transportation or sale of natural gas or [5] to

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60. For an overview of the history of the Act's inception, *see generally Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377-80, 103 S.Ct. 1905, 1908-10, 76 L.Ed.2d 1 (1983); *Panhandle Pipe Line Co. v. Public Serv. Comm'n*, 332 U.S. 507, 514-21, 68 S.Ct. 190, 193-98, 92 L.Ed. 128 (1947); *Illinois Natural Gas Co. v. Central Ill. Pub. Serv. Co.*, 314 U.S. 498, 504-08, 62 S.Ct. 384, 386-88, 86 L.Ed. 371 (1942); *National Ass'n of Regulatory Util. Comm'rs v. FERC*, 823 F.2d 1377, 1382-87 (10th Cir.1987).

> the local distribution of natural gas or to the facilities used for such distribution or [6] to the production or gathering of natural gas.

15 U.S.C. § 717(b).

Petitioners' jurisdictional challenges require us to interpret the first and fifth provisions of § 1(b), which address the interstate transportation and "local distribution" of natural gas.[61] In truth, the two provisions are a unity. "It is well established that the ["local distribution"] proviso was added to the Act merely for clarification and was not intended to deprive [FERC] of any jurisdiction otherwise granted by § 1(b)." *Louisiana Power & Light*, 406 U.S. at 637 n. 14, 92 S.Ct. at 1837 n. 14; *see also East Ohio Gas*, 338 U.S. at 469-70, 70 S.Ct. at 269 ("[W]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among consumers within a particular local community, not the high-pressure pipe lines transporting the gas to the local mains."). As explained in the House Report on the Act:

> That part of the negative declaration that the act shall not apply to "the local distribution of natural gas" is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the

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61. For an overview of the Commission's transportation jurisdiction, *see generally Louisiana Power & Light*, 406 U.S. at 636-40, 92 S.Ct. at 1836-38; *United Gas Pipe Line Co. v. FPC*, 385 U.S. 83, 89, 87 S.Ct. 265, 269, 17 L.Ed.2d 181 (1966); *East Ohio Gas*, 338 U.S. at 467-74, 70 S.Ct. at 268-72; *Cascade Natural Gas Corp. v. FERC*, 955 F.2d 1412, 1415-21 (10th Cir.1992); *Michigan Consol. Gas Co. v. FERC*, 883 F.2d 117, 121-22 (D.C.Cir.1989).

> Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.

H.R.REP. NO. 709, 75th Cong., 1st Sess. 3 (1937). And, as this circuit has concluded:

> Insofar as congressional committees spoke to the matter, therefore, they appear to have viewed distribution as confined to its parceling out function and (probably) even more narrowly, to parceling out accompanied by retail sales. As § 1(b) gave the Commission jurisdiction only over sales for resale, the states had unquestioned authority over retail sales anyway, making the reservation for distribution surplusage.

Public Utils. Comm'n v. FERC, 900 F.2d 269, 276 (D.C.Cir.1990).

We now consider whether FERC has done more than its interstate transportation jurisdiction permits.

1. *FERC's jurisdiction to regulate capacity release*

Petitioners' first jurisdictional challenge is the claim of the LDCs that FERC lacks any authority whatsoever to regulate shippers' resale of firm capacity rights. "LDCs' capacity assignments," they maintain, "involve sales of LDCs' rights to transportation service but do not involve interstate transportation or sale for resale of gas itself." As we understand their position,

the LDCs would limit FERC's regulatory authority over transportation to the rendition of interstate gas transportation services, as opposed to authority over the rights to receive those services. As their theory goes, the Commission has jurisdiction over the pipelines' initial sales of transportation capacity — given that it is the pipelines that render transportation services — but is without jurisdiction over resales of those same capacity rights by third parties — given that those third parties do not render transportation services.

Initially, we believe that the distinction drawn by the LDCs between the "rights to" and "rendition of" interstate transportation services is not a meaningful one. While the pipeline provides transportation only when a party utilizes capacity rights to transport gas, the pipeline provides transportation services throughout the capacity release process. Specifically, the pipeline operates the electronic bulletin board on which all prospective transactions are posted and consummated. The pipeline also selects the winning bidder in the transaction. Moreover, unlike capacity brokering arrangements, which occur directly between releasing and replacement shippers, capacity release requires the pipeline to contract with the replacement shipper. "In effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper. Both of these activities are subject to the Commission's jurisdiction under NGA section[ ] 1(b). . . ." Order No. 636-A, ¶ 30,939, at 30,551. In sum, the capacity release regulations operate as a term or condition of pipeline service, with which its customers must comply.

As an entirely separate matter, the Commission's jurisdiction attaches to the subject of the capacity resale

transaction: interstate transportation rights. "By controlling such capacity, the assignors are effectively determining by whom, and under what circumstances, gas will be transported and are using the pipeline's facilities as if they were the assignors' facilities." *Id.* (quotation marks, alteration, and citation omitted). In contrast, under the regulatory system envisioned by the LDCs, holders of capacity rights could engage in resales without regard to the principles of open access and nondiscrimination that are at the heart of the uniform capacity release system. Such a result is directly contrary to Congress' intent in enacting the Natural Gas Act. Responding to the Supreme Court's conclusion that the Constitution's dormant Commerce Clause prohibited state regulation of the interstate transportation of natural gas, *see supra* at 88, the federal government interceded to ensure stability and protect the interests of the consuming public. It thereby occupied the field, which necessarily includes both the sale and resale of interstate transportation rights.

2. *Jurisdiction over LDCs' capacity sales to their own end-users*

Several petitioners make more limited claims that specific classes of entities and transactions must be exempted from the Commission's control over capacity resales. First, the PUCs and LDCs together argue that FERC lacks jurisdiction over capacity sales by LDCs to their own end-users. Such transactions, they maintain, fall within the NGA's "local distribution" exemption. Specifically, according to petitioners, the Commission has always recognized that the states have jurisdiction to regulate bundled sales of natural gas by LDCs to their end-users, which necessarily involves some indirect influence over the interstate transportation element of the sale. State authority remains intact for LDCs' rebundled sales of gas and transportation even after

the implementation of Order No. 636. They contend that there is no functional difference between that jurisdictional arrangement and state regulation of LDCs' sales of unbundled gas and — more relevant here — transportation to local end-users. In particular, petitioners contend that state regulatory commissions need the freedom to control LDCs' assignment of capacity so that local end-users will be ensured of access to pipeline service.

But, as we have already explained, petitioners' reading of NGA § 1(b)'s reference to "local distribution" is flawed; the proviso does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas. In this regard, we find the Commission's explanation of the regulatory environment far more convincing. States have been — and are still — permitted to regulate LDCs' bundled sales of natural gas to end-users because those transactions include transportation over local mains and the retail sale of gas. In contrast, states have never regulated the terms and conditions of interstate pipeline transportation. When the gas sales element is severed — i.e., unbundled — from the transaction, FERC retains jurisdiction over the interstate transportation component.[62]

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62. The LDCs briefly argue that NGA § 1(c), the so-called 'Hinshaw exemption,' deprives the Commission of jurisdiction over their capacity sales to their own end-users. In this regard, they refer us to Congress' determination in § 1(c) that certain pipelines are "matters primarily of local concern and subject to regulation by the several States." 15 U.S.C. § 717(c). For the reasons set out in the text, however, the Commission's authority to regulate capacity release arises from its jurisdiction over the interstate pipeline that consummates the transaction and the subject of the transaction, the interstate transportation of gas, entirely independent of its jurisdiction over the releasing or replacement shipper. Accordingly, we reject the LDCs' claim, given that they do not suggest that FERC has improperly exercised jurisdiction over the release of capacity held on nonjurisdictional Hinshaw pipelines.

3. *Jurisdiction over municipal capacity release*

We now turn to the claim of the municipally owned local distribution companies ("municipalities") that FERC does not have jurisdiction to require them to comply with its capacity release regulations. Petitioners parse the terms of the Natural Gas Act as follows:

> Municipalities are exempt from the Commission's jurisdiction under the NGA. The Commission's NGA jurisdiction extends only to "natural gas companies." A "natural gas company" is defined in NGA Section 2(6) as "a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." NGA Section 2(1) defines a "person" as an "individual" or a "corporation." NGA Section 2(2) defines a "corporation" as inter alia, any corporation, partnership or association, but the definition expressly excludes "municipalities."

Small Distributors' and Municipalities' Br. at 11-12 (footnotes omitted).

Of course, as discussed above, *see supra* Part III.B.1, NGA § 1(b) extends the Commission's jurisdiction over not only "natural-gas companies" but also the interstate transportation of natural gas. FERC, however, has twice rejected the suggestion that it should invoke its transportation jurisdiction over

municipalities.[63] *See Tennessee Gas Pipeline Co.*, 69 F.E.R.C. ¶ 61,239, at 61,906-07 (1994), *reh'g denied*, 70 F.E.R.C. ¶ 61,329 (1995); *Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170, at 61,453-54 (1990). Accordingly, FERC wholly "agrees with [petitioners] that municipalities are beyond [its] jurisdiction." Order No. 636-A, ¶ 30,950, at 30,551.[64]

That notwithstanding, FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations. As we explained above, *see supra* Part III.B.1, FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas pipelines.[65] The pipelines' role in capacity release is absolutely

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63. Our opinion should not be read to either approve or disapprove the Commission's reading of the Natural Gas Act in this regard.

64. *Accord Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170 (1990) ("The Philadelphia Gas Works requests clarification that all the conditions imposed upon [capacity brokering] program participants do not apply to municipalities. Since municipalities are beyond the jurisdiction of this Commission, the Philadelphia Gas Works is correct."); *Northwest Alabama Gas District*, 42 F.E.R.C. ¶ 61,371, at 62,086, 1988 WL 391438 (1988) ("It is well settled that we cannot regulate a municipality under the NGA or the NGPA."); *Panhandle Eastern Pipe Line Co. v. City of Rolla*, 26 F.P.C. 736, 738 (1961) ("From [the plain language of the Natural Gas Act] it is clear that municipalities cannot be 'natural-gas companies' as that term is used by the Act. We are not, therefore, vested with jurisdiction to regulate municipalities, even though they are engaged in the sale of natural gas to interstate pipeline companies.").

65. Thus, in instituting the capacity release program, the Commission legitimately invoked its authority under NGA § 5 over "any rate, charge, or classification" or "any natural-gas company," 15 U.S.C. § 717d, given that pipelines are natural-gas companies under the Act.

central,[66] and the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers.[67]

The analogy drawn by the Commission, and the one we find most persuasive, is to the pipeline curtailment regime. As explained in Judge Rogers' opinion for the court, *see supra* Part II.C, pipelines at times must interrupt and redistribute their service based on shortages of both gas supply and pipeline capacity. The Supreme Court has expressly approved the Commission's authority to regulate such curtailments pursuant to its § 1(b) interstate transportation jurisdiction. *See Louisiana Power & Light Co.*, 406 U.S. at 640-41, 92 S.Ct. at 1838-39. The Commission's capacity release program is strikingly similar to its curtailment regulations, in that both involve the pipelines' allocation of transportation capacity among their shippers in compliance with federally mandated strictures. As the municipalities are subject to the curtailment regulations, so too must they comply with FERC's standards for capacity release.

We also find compelling the acknowledged jurisdictional arrangement prior to the implementation of either capacity

66. That factor distinguishes this case from the *Texas Eastern* proceedings, 51 F.E.R.C. ¶ 61,170 (1990), in which FERC concluded that it lacked jurisdiction to require municipal LDCs to comply with its capacity brokering standards.

67. The municipalities contend that the pipelines' involvement in capacity release is too ministerial to establish the Commission's jurisdiction. While we ultimately disagree with that argument for the reasons set forth in the text, we recognize its relevance. This could well be a different case had FERC in fact merely manipulated its regulations to involve the pipelines in a minimal way only to thereby create a jurisdictional toehold over a nonjurisdictional entity.

brokering or capacity release. At that time, shippers acquired firm capacity rights directly from pipelines on a first-come, first-served basis. Resales of capacity by shippers, including municipalities, simply did not occur. We therefore conclude that the Commission has jurisdiction to require open, nondiscriminatory capacity release by municipalities.

4. *Jurisdiction over "buy/sell" arrangements*

The final jurisdictional challenge to the capacity release mechanism involves "buy/sell" transactions, which FERC professed to bar[68] in Order No. 636 and the companion El Paso Natural Gas Co. proceedings, 59 F.E.R.C. ¶ 61,031, *reh'g denied*, 60 F.E.R.C. ¶ 61,117 (1992). "Buy/sells" occur in three stages. First, an end-user of gas either purchases or identifies certain natural gas at the point of production. The LDC that services the end-user then purchases the gas and transports it first under its own transportation rights on an interstate pipeline and later across its local distribution facilities.[69] The end-user then receives the gas from the LDC. The "buy/sells" reviewed by the

68. Buy/sell" agreements in place before the date that Order No. 636 went into effect were allowed to continue in force, but were required to be posted on the pipeline's electronic bulletin board for informational purposes. Order No. 636, ¶ 30,939, at 30,416-17.

69. Hadson Gas Co. contends that FERC has yet to make clear the precise nature of the transactions that it has prohibited. But as the Orders under review explain, the bar to "buy/sells" "applies to all firm capacity that is subject to the Order No. 636 capacity release program." Thus, in the now-prohibited transactions, an LDC holds title to gas specifically purchased by the LDC for the customer while utilizing its firm capacity rights to transport the designated gas over the interstate pipeline. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117. It is not, of course, necessarily the identical gas that the end-user receives at the delivery point.

Commission in the El Paso proceedings were conducted under the authority and oversight of the California Public Utility Commission.

FERC acknowledges that "buy/sell" transactions implicate legitimate state regulatory interests. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117, at 61,383-84. That said, given the transactions' intermediate stage — in which the end-user expressly arranges for the interstate transportation of specifically identified gas — the Commission contends that it has authority to preempt such state regulation. We therefore begin by setting forth settled principles of federal preemption.

a. *Introduction to federal preemption*

The Constitution provides that the laws of the federal government "shall be the supreme Law of the Land; . . . any Thing in the Constitution or Laws of any state to the Contrary notwithstanding." U.S. CONST. art. VI. That principle of supremacy is implemented through the doctrine of federal "preemption,"[70] under which state and local law may be stripped of its effect. Federal preemption may occur in a variety of circumstances:

> [1] It is well established that within constitutional limits Congress may pre-empt state authority by so stating in express terms.

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70. *See generally New York St. Conf. v. Travelers Ins. Co.*, __ U.S. __, __ - __, 115 S.Ct. 1671, 1676-77, 131 L.Ed.2d 695 (1995); *Cipollone v. Liggett Group*, 505 U.S. 504, 516, 112 S.Ct. 2608, 2617, 120 L.Ed.2d 407 (1992); *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248, 104 S.Ct. 615, 621, 78 L.Ed.2d 443 (1984); *Florida Lime & Avocado Growers v. Paul*, 373 U.S. 132, 141-42, 83 S.Ct. 1210, 1216-17, 10 L.Ed.2d 248 (1963).

> [2] Absent explicit pre-emptive language, Congress' intent to supersede state law altogether may be found from a scheme of federal regulation so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it, because [(a)] the Act of Congress may touch a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject, or [(b)] because the object sought to be obtained by the federal law and the character of obligations imposed by it may reveal the same purpose. [3] Even where Congress has not entirely displaced state regulation in a specific area, state law is pre-empted to the extent that it actually conflicts with federal law. Such a conflict arises when compliance with both federal and state regulations is [(a)] a physical impossibility, or [(b)] where state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.

Pacific Gas & Elec. Co. v. State Energy Resources Conserv. & Devel. Comm'n, 461 U.S. 190, 203-04, 103 S.Ct. 1713, 1722, 75 L.Ed.2d 752 (1983) (internal citations, quotation marks, and ellipses omitted).

Moreover, federal preemptive authority may be exercised not only through federal statutes but also regulations issued by

administrative agencies.[71] When an agency announces its intent to pre-empt state authority in a particular area,

> the correct focus is on the federal agency that seeks to displace state law and on the proper bounds of its lawful authority to undertake such action. The statutorily authorized regulations of an agency will pre-empt any state or local law that conflicts with such regulations or frustrates the purposes thereof. Beyond that, however, in proper circumstances the agency may determine that its authority is exclusive and pre-empts any state efforts to regulate in the forbidden area. It has long been recognized that many of the responsibilities conferred on federal agencies involve a broad grant of authority to reconcile conflicting policies. Where this is true, the Court has cautioned that even in the area of pre-emption, if the agency's choice to pre-empt represents a reasonable accommodation of conflicting policies that were committed to the agency's care by the statute, we should not disturb it unless it appears from the statute or its legislative history that the accommodation is not one that Congress would have sanctioned.

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71. *See generally Fidelity Fed. Sav. & Loan Ass'n v. de la Cuesta*, 458 U.S. 141, 152, 102 S.Ct. 3014, 3022, 73 L.Ed.2d 664 (1982); *Lincoln Sav. & Loan Ass'n v. Federal Home Loan Bank Bd.*, 856 F.2d 1558, 1560-61 (D.C.Cir.1988); *Conference of St. Bank Super. v. Conover*, 710 F.2d 878, 881-83 (D.C.Cir.1983).

City of New York v. FCC, 486 U.S. 57, 64, 108 S.Ct. 1637, 1642, 100 L.Ed.2d 48 (1988) (citations and quotation marks omitted) (emphasis added).

b. *Analysis*

We consider petitioners' arguments regarding "buy/sell" transactions under the branch of pre-emption doctrine that concerns "conflicts" between state and federal law, and particularly state law that "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Hines v. Davidowitz*, 312 U.S. 52, 67, 61 S.Ct. 399, 404, 85 L.Ed. 581 (1941). The Commission's goal in preempting "buy/sell" transactions was to preserve the integrity of its uniform capacity release program. *See El Paso Natural Gas*, 60 F.E.R.C. ¶ 61,117, at 61,385. Specifically, the Commission concluded that "buy/sells" offer a ready means of circumventing the open, nondiscriminatory bidding process central to capacity release. Under Order No. 636, an end-user seeking firm interstate transportation for gas that it has identified or acquired at the point of production must attempt to purchase capacity by contracting on the open market. In a "buy/sell" transaction, in contrast, the end-user can contract with an LDC without being forced to compete with other shippers that value the capacity. FERC reasoned that because "buy/sells" occur without open bidding, and result in the tying-up of interstate pipeline capacity, they circumvent and distort the transportation market envisioned by Order No. 636.[72]

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72. Hadson Gas Co. suggests that FERC "ignored relevant differences among shippers" in prohibiting all "buy/sell" arrangements, without regard to the market power of the particular shipper. In particular, Hadson contends that while LDCs may hold sufficiently substantial capacity rights to exercise

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The LDCs contend that preemption is inappropriate in this instance because the Commission's prohibition on "buy/sells" constitutes a regulation of the retail sale of natural gas, which Congress reserved to the jurisdiction of state regulatory bodies. While the Commission emphasizes the intermediate, transportation stage of the transaction, the LDCs focus on the terminal stage, describing "buy/sell" agreements as a classic instance of an LDC making a retail sale to a retail customer. *Cf. AGD I*, 824 F.2d at 995 ("LDCs purchase gas for resale to end users, large and small. Their services and prices are subject to state regulation but not to that of FERC."). As the LDCs characterize the transaction:

> A retail customer participating in a buy/sell arrangement with an LDC purchases the same product purchased by other retail gas customers: natural gas, delivered to the point of consumption, at a state-regulated price that includes the cost of (a) the gas; (b) the inter- and intrastate transportation required to move the gas from the market or production area to the point of consumption; and, (c) all other local distribution services, such as balancing and metering costs.

LDCs' Reply Br. at 8. Further, given the express terms of NGA

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market power, the same cannot be said of gas marketers. As FERC notes, however, when the capacity available for sale on a particular pipeline is limited, holders of even relatively small capacity allotments can exercise market power. Further, holders of smaller capacity shares are able to increase their market power by pooling their holdings and marketing them together. *See* Order No. 636-A, ¶ 30,950, at 30,558.

§ 1(b), the LDCs maintain that the Commission's jurisdiction cannot arise merely by means of some effect of "buy/sell" agreements on interstate transportation; such an interpretation of the Act would dramatically expand FERC's jurisdiction because almost all gas travels interstate and therefore almost all retail sales of gas affect interstate transportation. *See also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 308, 108 S.Ct. 1145, 1155, 99 L.Ed.2d 316 (1988) ("Of course, every state statute that has some indirect effect on rates and facilities of natural gas companies is not preempted."). Thus, conflict preemption analysis must be applied with particular care in those instances in which the Commission seeks to preempt state regulation merely because it has some effect on the interstate transportation of natural gas. *Northwest Central Pipeline v. State Corp. Comm'n*, 489 U.S. 493, 515- 16 & n. 12, 109 S.Ct. 1262, 1276-77 & n. 12, 103 L.Ed.2d 509 (1989).

We believe that the LDCs have confused two separate issues. While the Commission's rationale in preempting "buy/sells" is the transactions' effect on interstate transportation — namely, that "buy/sells" facilitate circumvention of the capacity release program — the Commission's authority is grounded in the transaction itself.[73] In the intermediate stage of a "buy/sell" transaction, the LDC carries the gas identified by the end-user

73. Indeed, it is in truth the LDCs that would bootstrap jurisdictional implications to the effects of Order No. 636. According to the LDCs, "buy/sell" agreements allow them to distribute and utilize their capacity rights more efficiently. This has as a secondary effect "lowering the unit cost of gas to" end-users, which the LDCs characterize as a "traditional and legitimate state interest[ ]." That proposition sweeps far too broadly. Almost every element of the Commission's regulation of interstate transportation affects distributors' costs, which must be passed on to local end-users. Regulation of interstate transportation is not thereby converted into a ground for exclusive state jurisdiction.

on its own firm capacity and under its own title on an interstate pipeline. Contrary to the LDCs' characterization, FERC's jurisdiction arises from the transportation itself; interstate transportation of gas selected by the end-user is a central element of the parties' agreement. As FERC states in its brief, "buy/sells" are "at bottom nothing more than agreements by which firm shippers allocate space on an interstate pipeline to customers who negotiate their own wellhead transactions." Transactions that do not include this transportation element are not "buy/sells" and are not preempted.

In a standard retail sale, by contrast, the end-user purchases gas from an LDC at the local delivery point without regard to aspects of gas transportation at points further upstream. *See id.* at 97 ("Traditional LDC retail sales consisted of sales of gas to local customers from generic system supply through local distribution facilities after the gas had completed its interstate journey."). Order No. 636 does not prohibit or condition such sales. Nor does the Order preempt state regulatory agencies from modifying an LDC's rate structure to accommodate differences in local conditions. Further still, LDCs remain free to sell gas to retail customers under the terms and conditions set by state regulators. Under Order No. 636, an end-user that would previously have engaged in a "buy/sell" transaction will still purchase the gas from the producer and still receive the gas at its delivery point. The crucial difference is that the end-user must purchase capacity rights from the LDC in the open market through the capacity release mechanism rather than by transferring title to the gas to the LDC and regaining title at the local delivery point.

Accordingly, we sustain the Commission's determination to pre-empt state regulation of "buy/sell" transactions. FERC's

effort to avoid circumvention of its capacity release regulations "represents a reasonable accommodation of conflicting policies that were committed to [its] care" under the Natural Gas Act. *City of New York*, 486 U.S. at 64, 108 S.Ct. at 1642. Further, given that the regulations do not impinge upon state control over retail gas sales, it appears that the Commission's accommodation is one that Congress would have sanctioned. *See id.*

C. *Substantive Challenges*

1. *Exclusion of Part 157 shippers from capacity release*

In Order No. 636-A, the Commission concluded that only "Part 284" blanket-certificated shippers would be permitted to engage in capacity release and utilize flexible receipt and delivery points. Order No. 636-A, ¶ 30,950, at 30,565. The Electric Generator Petitioners ("Electric Generators") contend that FERC's exclusion of Part 157 "individually certificated" shippers[74] was arbitrary and capricious. Their theory is that capacity release and flexible receipt and delivery points were intended to compensate for the greater costs of straight-fixed-variable rate design, which both Part 284 and Part 157 shippers are subject to; excluding Part 157 shippers from capacity release therefore allegedly deprives them of a necessary and equivalent means of cost mitigation. They also contend that subjecting Part 157 shippers to SFV rate design while excluding them from capacity release is unduly discriminatory, given that both SFV

74. These shippers transport gas pursuant to individual certificates issued by the Commission under Part 157 of its regulations. The critical difference between Part 157 and Part 284 shippers is that Part 157 shippers have always been able to transport non-pipeline owned gas, while Part 284 shippers generally have had that capability only since the promulgation of Order No. 436. *See MPC I*, 761 F.2d at 782.

rate design and capacity release were intended to develop a national natural gas market.

The Commission's decision to exclude Part 157 shippers from capacity release and flexible receipt and delivery points was not arbitrary and capricious. While capacity release does ameliorate the costs of SFV rate design, it was never intended as the central cost-mitigation measure, *see* Order No. 636-A, ¶ 30,950, at 30,594, 30,597-98, for there are specific mechanisms in place intended to address the particular costs associated with SFV, including alternative ratemaking techniques, phase-in measures, and the continued use of one-part rates for small customers. *See infra* Part IV.C.1. Moreover, allowing individually certificated shippers to utilize capacity release would in effect require Part 284 shippers to subsidize their Part 157 counterparts, given that Part 284 shippers pay costs that Part 157 shippers do not.[75] Specifically, Part 157 shippers are not required to pay the transition costs of Order No. 636, and

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75. The Electric Generators maintain that their exclusion from capacity release represents a downgrade in their service because Order No. 636 also prohibited them from selling capacity under the Commission's predecessor "capacity brokering" program. They contend that because the Commission is eliminating a pre-existing program, it is obligated to offer a particularly persuasive rationale for its decision. *Cf. Williams Natural Gas Co. v. FERC*, 872 F.2d 438, 444 (D.C.Cir.1989). But, as FERC notes, capacity brokering was authorized on only a few pipelines, so that widespread capacity release is in fact a major service upgrade. Moreover, the Commission's rationale in implementing capacity release applies equally to its decision to bar Part 157 customers from continuing to engage in capacity brokering, and is persuasive. Finally, as the Commission maintains, and the Electric Generators essentially concede in their reply brief, FERC's policy granting Part 157 shippers access to capacity brokering "was a settlement, was expressly limited to the facts in that proceeding, was adopted only on an interim basis, and was never intended to survive Order No. 636."

their transportation arrangements are not subject to pre-granted abandonment. Further, the Commission prohibits Part 157 shippers, which do not operate under open-access provisions, from including unique terms and conditions in their contracts in order to avoid undue discrimination. For that very reason, the Commission prohibits Part 157 shippers from granting discounts, which itself presents a major obstacle to Part 157 shippers' participation in capacity release because competitive bidding presumes the ability to offer a lower price.

The Electric Generators reply that these factors have no connection to the cost-mitigation effects of the capacity release program. The more salient issue, however, is whether the factors identified by either the Commission or the Electric Generators have any intrinsic connection to SFV rate design; they do not. Fundamentally, the petitioners contend that they are entitled to release capacity as one way of making up for the costs of SFV. FERC replies, quite sensibly, that while capacity release would reduce the Electric Generators' costs, including costs associated with SFV, the Electric Generators are already receiving cost benefits not available to Part 284 customers, and are not entitled to further benefits.

Nor was the Commission's decision to exclude Part 157 shippers unduly discriminatory. The Commission applied SFV rate design to both Part 284 and Part 157 shippers because both generally have been subject to the same rate design. *See* Order No. 636-B, ¶ 61,272, at 61,992. Even if the goal of both SFV rate design and capacity release is the creation of a national gas market, that does not mean that FERC's decision to apply only one to Part 157 shippers constitutes undue discrimination. "[T]he competitive rationale for adopting SFV rate design as a means to promote the development of a national gas market applies

equally to [Part 284 and] Part 157 rates." *Id.* While allowing Part 157 shippers to engage in capacity release might expand the national gas marketplace, as we have explained, it would also give them an unfair subsidy over Part 284 shippers. As FERC notes in its brief, "[g]iven the significant differences between these two forms of service under Order No. 636, it was not unreasonable to confine the capacity release program to Part 284 open access service." We see no reason to disturb the Commission's conclusion that those cost considerations outweighed any benefit to the national gas marketplace and disentitled Part 157 shippers from engaging in capacity release.

Moreover, as the Commission explains, the Electric Generators may receive access to capacity release and flexible receipt and delivery points by converting to Part 284 service. This does not mean, as petitioners contend, that the Commission is unlawfully attempting to leverage the Electric Generators' conversion. Here, we reject petitioners' reliance on *National Fuel Gas Supply Corp. v. FERC*, 909 F.2d 1519 (D.C.Cir.1990). In *National Fuel*, this court turned back an effort by FERC to condition its certification of a Part 157 shipper's gas services on the shipper's obtaining a blanket Part 284 certificate as well. Our ruling there was based on the fact that the Commission had already determined that a Part 157 certificate was "required by the public convenience and necessity" when it nonetheless attempted to add the additional condition of acquiring a Part 284 certificate. Given the Commission's conclusion that the shipper was already entitled to a Part 157 certificate, "[i]t was thus clear at the outset that the Commission considered certification . . . to be in the public interest regardless of whether the pipeline also accepted a blanket transportation certificate." *Id.* at 1522. FERC therefore lacked authority to deny the shipper a Part 157 certificate. In this case, in contrast, the Electric

Generators do not contend that the Commission has determined that Part 157 shippers have the right to engage in a certain service, but is nonetheless denying them the right to engage in it. Moreover, even under the petitioners' far more expansive reading of *National Fuel*, this is not an instance in which FERC is attempting to coerce a conversion from Part 157 to Part 284 service; the Commission is simply pointing out that conversion offers the Electric Generators one means of cost-mitigation.

2. *The standard for determining the best bid*

The LDCs and Industrial End-Users raise three challenges to the methods selected by the Commission for determining the prevailing bidder and price in the capacity release transaction. In Order No. 636, FERC concluded that conditions set by LDCs on their release of capacity "must not prefer any shipper, such as an end-user, over other shippers, and cannot take into account the use of the LDC's own facilities." Order No. 636-B, ¶ 61,272, at 61,997. The LDCs maintain that, in a market sense, this rule prohibits them from selecting what is truly the "best" bid, *i.e.*, "one that reflects [the] greatest economic benefit to the releasing shipper." Specifically, the LDCs want the right to favor their own end-users in capacity sales, a practice that ultimately would reduce the LDCs' own costs. But that is not a right to which they are entitled under the Natural Gas Act. The LDCs' claim is at bottom nothing more than an objection to FERC's open-access, nondiscrimination policy. The goal of capacity release is to create a uniform national market for transportation, not to maximize the benefit to LDCs. Only by utilizing nondiscriminatory factors in determining the prevailing bid can FERC ensure that the shipper that places the highest value on capacity receives it.

The Industrial End-Users make the related argument that FERC acted arbitrarily in refusing to grant a bidding preference to LDCs' existing end-users. In particular, they note that FERC did grant existing end-users a preference in acquiring capacity released by upstream pipelines under the section 284.242 mandatory capacity release program. As with the immediately preceding claim, however, the standard set by FERC fundamentally is part of its nondiscrimination and open-access policy. Moreover, as FERC notes, an end-user can be sure of receiving capacity by entering into a pre-arranged deal with its LDC at the maximum allowable price.[76] The preference granted under the mandatory program, in contrast, is unrelated to the development of a transportation market through capacity release; it is specifically intended to ensure that when pipelines engage in unbundling, their end-users are not deprived of the transportation necessary to fulfill their pre-existing gas needs.

The Electric Generators finally contend that FERC should not uniformly have set the maximum allowable rate for resales of capacity at the originally determined maximum rate. They contend that this will in some instances result in discrimination against shippers who pay higher initial "incremental" rates.[77] The Commission responds that this issue is too complex and fact-bound to address in the overarching Order No. 636

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76. While an LDC could conceivably refuse to make such a deal, it would have no incentive to do so because no other transaction can provide it with a higher price. Further, as the Commission notes in its brief, claims that an LDC discriminated against its end-users in allocating capacity may be addressed through the NGA § 5 complaint procedure.

77. For a discussion of incremental rates, *see generally TransCanada PipeLines Ltd. v. FERC*, 24 F.3d 305, 308-11 (D.C.Cir.1994); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312-14 (D.C.Cir.1991).

proceedings, and that it should be deferred to the restructuring proceedings, where a better record can be developed. *See* Order No. 636-A, ¶ 30,950, at 30,561 ("[T]he parties in restructuring proceedings involving incremental rates should consider and propose methodologies to ensure that the capacity release mechanism operates efficiently and that all parties are treated fairly and equitably, without undue discrimination."). We agree. The Electric Generators' explication of their claim in these proceedings is far too sparse to allow for reasoned evaluation, primarily because the relevant factual record is not before us. Their claim may properly be evaluated by the Commission in individual restructuring proceedings where further facts can be developed.

3. *Interruptible transportation revenue crediting*

After the implementation of capacity release under Order No. 636, the number of firm transportation sellers in the marketplace substantially increased. As a result, it became difficult for pipelines to determine how much demand there will be for interruptible transportation ("IT") service. In turn, it is difficult for the pipelines to determine what portion of their costs to recoup through billings to IT (as opposed to firm) service. In the Order No. 636 proceedings, FERC suggested that a pipeline

> might decide to attribute no revenue responsibility to interruptible transportation. Since the pipeline's firm shippers would be responsible for all pipeline costs, revenues from the sale of interruptible transportation would [later] be credited to the firm shippers.

Order No. 636-A, ¶ 30,950, at 30,563. Under true cost

accounting, 100% of IT revenues would be credited to firm shippers, because firm customers are essentially being overcharged until the pipeline can figure out how much money it is recovering from IT service. The Commission suggested, however, that pipelines might adopt a 90/10 mechanism, under which only 90% of IT revenues would be credited to firm shippers. This 10% difference was thought by FERC to be a necessary incentive for pipelines to market interruptible transportation. Without it, pipelines would be assured of recovering their costs through firm sales charges, and therefore would have no reason to maximize IT throughput.

The Industrial End-Users, who utilize interruptible transportation, challenge the Commission's endorsement of a 90/10 IT revenue crediting mechanism on two grounds. First, they argue that the 10% gain creates an insufficient incentive for pipelines to market IT. The Industrial End-Users note that FERC rejected proposals for revenue crediting under Order No. 436, because they "give[ ] the pipeline little or no incentive to provide service under the rule." Order No. 436, ¶ 30,665, at 31,537. Second, they argue that the 90/10 mechanism reduces other shippers' incentive to release capacity; shippers know that if they do not put their firm capacity on the market, thereby forcing other companies to utilize IT service, they will receive some portion of the IT revenues through the crediting mechanism anyway. We conclude that the Industrial End-Users' challenge to the IT revenue crediting mechanism is premature. Order No. 636-A expressly provides that pipelines "might" adopt this "potential approach," and that "parties to the restructuring proceedings also may consider whether other methods are needed." Order No. 636-A, ¶ 30,950, at 30,563; *see also* Order No. 636-B, ¶ 61,272, at 62,000 ("[T]he parties to the restructuring proceedings could consider a variety of approaches,

such as agreeing on an appropriate level of throughput for interruptible transportation or some type of revenue crediting mechanism.").[78] Our concerns are magnified given that the Industrial End-Users maintain that the 10% pipeline credit does not provide pipelines with a sufficient incentive to market IT, but provide no data or explanation of why that is the case. The only way to evaluate their claim is in the light of the particular facts presented in individual pipelines' restructuring proceedings. *See id.* ("The petitioners requesting rehearing have not been aggrieved by the suggestion that the Commission would consider a revenue crediting approach proposed in a specific restructuring proceeding. In implementing its regulations, the Commission will not adopt rigid rate-making methodologies that fail to reflect the reality of the market or the intent of its regulations."). We therefore defer resolution of the Industrial End-Users' IT revenue crediting challenge to the individual pipeline restructuring proceedings.

D. *Conclusion*

We deny the petitions for review insofar as they dispute the Commission's jurisdiction over capacity release transactions. We further deny the petitions for review insofar as they challenge (1) the exclusion of Part 157 shippers from the capacity release program, (2) the mechanism chosen by the Commission for determining the best bid in capacity release transactions, and (3) the Commission's suggestion that a 90/10 mechanism is an appropriate means of crediting interruptible transportation revenues. We specifically defer to later proceedings

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78. While the Industrial End-Users contend that the Commission has been applying the 90/10 mechanism as a rigid rule, they concede that it approved an 80/20 mechanism in *CNG Transmission Corp.*, 64 F.E.R.C. ¶ 61,082, at 61,776-66 (1993).

consideration of the merits of both the revenue crediting mechanism and the Commission's treatment of incremental rates.

IV. Rate Design

Various petitioners raise three major challenges to the rate design portion of the Order No. 636 series. As noted above, FERC ordered a change from the preexisting modified fixed variable (MFV) to a straight fixed variable (SFV) rate design. First, petitioners question whether FERC has authority under the NGA to adopt SFV rate design. Second, they question whether FERC's decision to switch from MFV rate design to SFV rate design was a reasonable one. Third, they question whether the mitigation measures FERC employed to ease the shift to SFV rate design are within FERC's ratemaking discretion.

A. *FERC's Authority to Adopt SFV Rate Design*

1. *MFV rate design's anticompetitive effects*

FERC's authority over rate design in this case derives from NGA § 5, which requires it to replace any "unjust, unreasonable, unduly discriminatory, or preferential" rate, charge or classification charged "by any natural-gas company in connection with any transportation or sale of natural gas" with a "just and reasonable rate, charge, [or] classification." 15 U.S.C. § 717d. Under the preexisting MFV design, the pipelines incorporated into commodity charges to their sales customers and usage charges to their transportation customers fixed costs that varied greatly from pipeline to pipeline. Accordingly, the unit prices to gas customers did not accurately reflect the actual

variable cost of supplying gas, because producers in different gas fields "compete for market share via different pipelines," so that their competitive positions in the market reflected the fixed costs in the pipelines' respective transportation usage charges and not simply "the producers' own costs and efficiencies in producing gas." Order No. 636, ¶ 30,939, at 30,434. The Commission concluded that a shift to the SFV rate design, under which the usage charges accurately reflect the actual variable costs of delivering gas, would remove this impediment to efficient competition.

The LDC petitioners[79] argue that FERC had no authority to take regulatory action on the basis of MFV rate design's anticompetitive effects on gas producers. They admit that FERC must consider the anticompetitive effects of rate design systems, but contend that FERC can only consider the anticompetitive effects of a system on entities it regulates directly (*i.e.*, pipelines themselves), not on unregulated industries such as gas producers, and they argue that MFV's anticompetitive effect on gas suppliers does not constitute an anticompetitive effect on pipelines. The LDCs cite in support of their position *Official Airline Guides, Inc. v. Federal Trade Comm'n*, 630 F.2d 920, 927-28 (2d Cir.1980), *cert. denied*, 450 U.S. 917, 101 S.Ct. 1362, 67 L.Ed.2d 343 (1981), in which the Second Circuit struck down a Federal Trade Commission (FTC) ruling that a monopoly airline guide publisher's refusal to publish flight schedules for certain airlines impaired competition in the airline industry. The Second Circuit held that the FTC Act's power to proscribe anticompetitive conduct did not extend to the restraint of a business's practices solely because of the conduct's incidental effect on competition between third parties in another industry.

79. LDC petitioners presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co. Washington Gas Light Co. is a supporting intervenor.

As the LDCs stress, antitrust policy "does not outlaw the practices of a party solely because those practices may indirectly affect competition between other entities with which it does not compete." Though the LDCs' premise is valid, it does not answer the question of whether FERC has the authority to consider anticompetitive effects on unregulated segments of the gas industry in setting rates for the regulated pipelines. The Second Circuit's decision simply does not purport to answer that question. Rather, the Official Airline Guides court was extending the doctrine established in *United States v. Colgate & Co.*, 250 U.S. 300, 307, 39 S.Ct. 465, 468, 63 L.Ed. 992 (1919) (as quoted in Official Airline Guides, 630 F.2d at 925), that, "[i]n the absence of any purpose to create or maintain a monopoly," antitrust policy "does not restrict the long recognized right of trader or manufacturer engaged in an entirely private business, freely to exercise his own independent discretion as to parties with whom he will deal." In fact, the Official Airline Guides court noted the dangers of departing from this principle of independent business judgment: "[W]e think enforcement of the FTC's order here would give the FTC too much power to substitute its own business judgment for that of the monopolist in any decision that arguably affects competition in another industry." *Official Airline Guides*, 630 F.2d at 927.

In contrast, FERC's decision in Order No. 636 represents not the rolling back of an independent business judgment because of its anticompetitive effect on an unrelated industry, but rather the substitution of one administratively imposed ratemaking regime for another based on the anticompetitive effect of the preexisting regime on unregulated entities dealing through regulated entities in a partially regulated segment of the economy — that is, the regulated pipeline segment of the partially regulated natural gas industry. The Commission's

express duty under NGA § 5 to set aside rates and practices that it finds unjust, unreasonable, unduly discriminatory, or preferential is not limited to the remedies that the FTC may order in an unregulated market; nor is FERC's basis for the exercise of that authority necessarily as limited as the FTC's bases for enforcement decisionmaking. Antitrust policies governing the FTC in the unregulated market do not exhaust the public interest grounds on which the Commission may order a change in rates under NGA § 5. Here, given that we review the Commission's acts under the deferential "substantial evidence" standard, 15 U.S.C. § 717r(b); *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C.Cir.1992), we hold that the Commission adequately justified its exercise of its authority when it stated that its ratemaking authority "includes the establishing of just and reasonable transportation rates that maximize the benefits of decontrol to gas consumers," Order No. 636-A, ¶ 30,950, at 30,594-95, and that regulated transportation rates "should in no way inhibit the creation of a national gas market of efficient gas merchants as envisioned by Congress in enacting the Decontrol Act." Order No. 636, ¶ 30,939, at 30,433. Unlike the FTC in *Official Airline Guides*, FERC was not attempting to limit the options of a free business actor in order to promote competition in an adjacent industry, but only to prevent the regulatorily imposed price decisions of a regulated industry from creating anticompetitive factors in economically adjacent markets.

2. *SFV rate design and NGA § 5*

The PUCs argue that FERC's ordering of the switch to SFV rate design exceeds its statutory authority. Under the NGA, FERC draws its ratesetting authority from two sections: NGA § 4 (15 U.S.C. § 717c) authorizes FERC to accept or reject rates

and rate adjustments filed by natural gas companies; and NGA § 5 (15 U.S.C. § 717d) authorizes FERC after a hearing and upon findings that an existing rate is "unjust, unreasonable, unduly discriminatory, or preferential" to fix "just and reasonable rate[s] . . . by order." The PUCs contend, and FERC admits if we reach the merits, that the Commission draws its authority in the present restructuring from § 5, or not at all, as no natural gas company has filed the rate structure which FERC is imposing. The PUCs argue that FERC's order imposing the new rate structure exceeds its authority under § 5 because that section expressly provides "[t]hat the Commission shall have no power to order any increase in any rate contained in the currently effective schedule" then on file with the Commission. Because the new rate structure will result in an increase in charges to some customers, the PUCs argue that FERC's order violates this provision.

FERC first contends that this rate increase argument is not properly before the court "because none of these petitioners raised it before the Commission in their requests for rehearing of Order No. 636." As FERC rightly suggests, the party who raises an issue in a petition for review must have raised the same issue in its petition for rehearing before the agency. *ASARCO, Inc. v. FERC*, 777 F.2d 764, 773-75 (D.C.Cir.1985). However, Atlanta Gas Light Company (Atlanta) and Chattanooga Gas Company (Chattanooga) specifically raised the rate increase argument in their petition for rehearing of Order No. 636. Request of Atlanta Gas Light Company and Chattanooga Gas Company for Rehearing and Clarification at 14-16 (May 8, 1992). And in the LDCs' brief in this court, several LDCs (including Atlanta and Chattanooga) cross-reference the PUCs' presentation of the rate increase argument, thereby incorporating the argument into the LDC brief before us, because Atlanta and

Chattanooga raised the rate increase argument in their petition for rehearing before FERC and raise it again in the present proceeding, the argument is properly before us, and we must consider it on its merits.

In Order No. 636-A, FERC disposed of the rate increase argument by relying on *ANR Pipeline Co. v. FERC*, 863 F.2d 959 (D.C.Cir.1988). In that case a pipeline filed a § 4 schedule to implement a rate reduction. Order No. 636-A, ¶ 30,950, at 30,666. FERC, using its § 5 authority, determined that the pipeline's rate design methodology was unjust and unreasonable (when a pipeline files a § 4 rate schedule, FERC can transform the proceedings into a § 5 action. *Western Resources, Inc. v. FERC*, 9 F.3d 1568, 1579 (D.C.Cir.1993)), and ordered the company to implement MFV rate design and to eliminate its minimum billing practice. Under the minimum billing practice, certain customers "were obligated to pay ANR, in each contract year, an amount equal to the fixed-cost portion of the commodity rate times the greater of (1) the volume actually purchased by the customer, or (2) a 'minimum bill quantity' (MBQ) specified by contract." *ANR Pipeline*, 863 F.2d at 960; *see also supra* at 68 n. 29 (describing minimum billing practices). One of ANR's largest customers, Michigan Consolidated Gas Company (MichCon), was paying more than its allocatable share of fixed costs because of the minimum bill requirement. *ANR Pipeline*, 863 F.2d at 960. Once ANR eliminated the minimum bill in compliance with FERC's order, it recalculated the per-unit share of fixed costs based on the decreased number of total units over which to allocate fixed costs. (After eliminating the minimum bill, the projected number of units over which to allocate fixed costs necessarily decreased for MichCon, since MichCon had not purchased and was not expected to purchase the MBQ of gas.). As a result, the per-unit share of fixed costs incorporated in the commodity charge went up.

Appendix A

Although FERC initially rejected ANR's proposed "increase" in commodity rates as a violation of the filed rate doctrine, we reversed that decision, concluding that FERC "had not rationally explained why its requirement that ANR's minimum bill had to be removed would not authorize the removal of volumes attributable to the minimum bill for purposes of calculating the amount of the fixed-cost commodity charge." Order No. 636-A, ¶ 30,950, at 30,667. The Commission therefore reads *ANR Pipeline* as standing for the proposition that "when the Commission orders a pipeline to implement a different rate design method that requires reductions in one component of the pipeline's rates, it must permit the pipeline to implement offsetting increases in some other component simultaneously in order for the pipeline to recover its cost of service." *Id.*

FERC's argument based on *ANR Pipeline* is a powerful one. Our reasoning in *ANR* supports a small scale version of the large scale balanced restructuring with offsetting features that FERC has ordered in the present proceeding. *ANR* is not, however, totally dispositive. The issue in that case came to us at a later stage. In *ANR*, after the Commission had made its initial § 5 ruling, the pipeline had made a compliance filing. That filing incorporated the contested "increase." Reviewing FERC's rejection of the compliance filing, we could not conclude that the Commission had "rationally explained why that filing [did] not comport with" the earlier instruction to the submitting pipeline. *ANR Pipeline*, 863 F.2d at 964. We did not therefore purport to authoritatively decide the breadth of the limitation in § 5 providing "that the Commission shall have no power to order any increase . . . unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d. That is, we did not determine how that section applies in the case of a Commission-initiated rate restructuring which,

while reducing rates for some customers, necessarily offsets that reduction by an at least present increase in the share borne by others. Thus, *ANR* is at best persuasive rather than controlling authority in favor of the Commission's asserted power to order a restructuring that results in increasing some components to the detriment of some pipeline customers.

Also relevant to our determination of the issue is our decision in *Western Resources Inc. v. FERC*, 9 F.3d 1568 (D.C.Cir.1993). In that case, the existing schedule included a "forward-haul rate" of approximately 20.05 cents per Mcf and a "backhaul rate" of one cent per Mcf. *Id.* at 1571. The pipeline filed a § 4 revised tariff sheet featuring increases in both the forward-haul and backhaul rates, making them equal to one another at a level above the former 20.05 cents per Mcf forward-haul rate. *Id.* FERC approved the forward-haul rate increase, but set the new backhaul rate at one-half the forward-haul rate. *Id.* at 1571-72. We remanded the case to FERC, however, holding that it had failed to sufficiently justify its decision as to the forward-haul rate and that it had improperly concluded that it could use its § 4 authority to grant half the requested backhaul increase. We determined that FERC's decision to increase the backhaul rate to only half the level requested was so far removed from the requested increase that it constituted an exercise of § 5 authority and not § 4. *See id.* at 1578-79. We remanded the backhaul increase on the grounds that FERC had not met the burden of proof imposed on it by § 5. *See id.* at 1580. Our opinion in *Western Resources* is susceptible of two interpretations. First, because we remanded for further consideration rather than vacating altogether a Commission order that amounted to a restructuring under § 5 including component increases, we implicitly concluded that FERC had the general authority to conduct such restructuring and only remanded for a

determination as to FERC's use of that authority on the specific rate before it. In *Western Resources*, the turning point of our decision was that FERC had erroneously purported to use § 4 authority where it was unavailable. As § 5 authority was the only authority left, if FERC had acted properly at all, it must have been under § 5. Our *Western Resources* opinion is also subject to the interpretation that in that case we remanded to FERC for the possibility of a rate decrease under § 5, considering the relevant baseline to be the pipeline's § 4 submission, which proposed rates higher than those that the Commission was willing to approve. Under the first of these possible interpretations, our remand to the Commission to reconsider its action under § 5 may carry some implication that we deemed it to have the authority it purports to use now, but that implication is not a strong one, and again, our existing circuit law at most inclines us toward FERC's position but does not compel us to adopt it. Under the second possible interpretation of *Western Resources*, the case is simply not on point at all.

We therefore today for the first time authoritatively determine the issue of whether a § 5 rate restructuring that includes an increase in some rate components to the detriment of some customers amounts to a prohibited "rate increase" under § 5 itself. As FERC claims this authority under the Natural Gas Act, a statute committed to its administration, we review the Commission's decision under the deferential standard dictated in *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842-43, 104 S.Ct. 2778, 2781-82, 81 L.Ed.2d 694 (1984). At the first step of that familiar two-step inquiry, we ask "whether Congress has directly spoken to the precise question at issue." *Id.* at 842, 104 S.Ct. at 2781. That is the point at which our inquiry ends "if we can come to the unmistakable conclusion that Congress had an intention on the

precise question at issue," Nuclear *Information Resource Service v. NRC*, 969 F.2d 1169, 1173 (D.C.Cir.1992) (in banc) (internal quotations and citations omitted). This is not such a case.

In reaching that conclusion we have examined first the plain language of the statute. The relevant text states: "[T]he Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d(a). At first reading, it may be most natural to suppose that Congress included within the prohibition against "any increase in any rate" a preclusion of Commission orders for rate restructuring that would ultimately lead to rate increases for some pipeline customers. However, supposition and first reading are not the stuff of unambiguous expressions of intent, and the plain language does not convince us that Congress unambiguously intended the interpretation petitioners support. To further inform our inquiry into congressional intent, we examine the complete statutory scheme. *Davis v. Michigan Dep't of the Treasury*, 489 U.S. 803, 809, 109 S.Ct. 1500, 1504, 103 L.Ed.2d 891 (1989) ("It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme."). The scheme considered under the NGA today contemplates that FERC must act consistently with the Natural Gas Wellhead Decontrol Act of 1989, Pub.L. No. 101-60, 103 Stat. 157 (1989), as well. That enactment contemplates a considerably changed natural gas world in which regulation plays a much reduced role and the free market operates at the wellhead. While a court construing congressional intent in one enactment should not be too greatly influenced by the enactments of a later Congress, we must necessarily consider the duties faced by an agency in examining its construction of its enabling

acts. While this part of our analysis usually occurs at the second step of *Chevron*, it is not irrelevant to the first. A commission charged with the regulation of the rates of an industry may be expected to restructure its general mandates when its world changes. If the enabling act under which it operates can be construed so as to give it that authority, that construction should not be ruled out in the absence of a genuinely unambiguous expression of a congressional intent to the contrary. The general language prohibiting "rate increases" under § 5 is not so plainly directed at such a preclusion.

Insofar as legislative history is an appropriate guide to the unambiguous intent of Congress, the little available in the present instance argues against rather than for the claim of unambiguous congressional intent advanced by petitioners. At the time of the adoption of the NGA, Representative Clarence Lea, a principal sponsor of the NGA and chairman of the committee which reported it to the House, declared that "[t]he purpose of [the amendment creating the § 5 rate increase prohibition] was to prevent any company's rates being raised over their objection, with the idea of stifling competition with a competitor." 83 CONG. REC. 9101 (1938) (Statement of Rep. Lea). Under this interpretation, the prohibition was included not so much for the protection of gas consumers from rate increases, but to protect a pipeline disfavored by FERC from suffering under FERC-imposed rate increases that would harm the pipeline's ability to compete. While it is not of course impossible for a statute to have two purposes, the intent advanced by Lea supports the proposition that Congress did not unambiguously intend that § 5 would protect customers from restructured rate designs ultimately leading to increased charges. In short, § 5 is not unambiguous. The provision may easily be read to prohibit FERC from ordering increases in specific filed rates while

leaving it free to order the restructuring of rates as it has attempted to do here.

As we have found that the statute is not unambiguous with respect to the specific issue before us, we proceed to the second step of the *Chevron* analysis. "At this stage, we defer to the agency's interpretation of the statute if it is reasonable and consistent with the statute's purpose." *Nuclear Information Resource Service*, 969 F.2d at 1173 (internal quotations and citation omitted). Having already observed in our step one analysis that the Commission's interpretation is consistent with the structure and purpose of the statute, we have no difficulty in finding that interpretation a reasonable one at step two. The petitioners' proffered interpretation is also a reasonable, indeed, perhaps a more natural interpretation of the statutory language. That, however, is not the standard. Even if we were convinced that the petitioners' interpretation were the better one, "we are not free to impose our own construction on the statute, as would be necessary in the absence of an administrative interpretation." *Id.* (internal quotations, brackets, and citation omitted). The only question is whether the agency's interpretation is reasonable and consistent with the statutory purpose. The answer to that question is yes. FERC undoubtedly has the authority to restructure pipeline rate calculation mechanisms, as long as it does so in an otherwise lawful manner and supports its actions with substantial evidence. Any restructuring, even if it does not alter a pipeline's revenues by one cent, will virtually always increase by some amount the charges that some individual customers pay and decrease the charges to some others. Reading § 5 in such a way that these increases for some customers constitute prohibited "rate increases" leads to the conclusion that FERC has no authority to restructure pipeline rates at all. FERC is not required to so interpret the statute.

Appendix A

B. *SFV Rate Design and Substantial Evidence*

1. *MFV rate design's distortions of the natural gas market*

For several decades, FERC's ratemaking regime has included some portion of a pipeline's fixed costs in the pipeline's commodity and usage charges. Over the years, it varied the specific percentage of fixed costs actually included in those charges, but it generally followed the principle that some portion of fixed costs should be recouped through quantity-dependent charges.[80] In 1986, the Seventh Circuit upheld FERC's 1983 adoption of the MFV rate design in use prior to the promulgation of Order No. 636. *See* Order No. 636, ¶ 30,939, at 30,432 (citing *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir.1986)). The PUCs argue that FERC cannot depart from this approved use of MFV rate design without giving a reasonable justification for doing so, and that FERC has failed to do so in the Order No. 636 series. They claim that FERC's determination that MFV distorts the gas market is inconsistent with prior FERC decisions and court rulings approving of MFV. Essentially, they maintain that if MFV was good in the past, it must still be good today. Additionally, the PUCs find plenty of evidence of competitive markets under MFV rate design, and they maintain that dropping MFV rate design is therefore improper. Finally, they stress that the full incorporation of fixed costs in variable charges seems to work well for the oil pipeline industry, so it should also work in the case of gas pipelines.

As the Supreme Court has noted, "[a]llocation of costs is

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80. It does appear that the Commission has used a rate design method similar to SFV in the distant past of natural gas regulation. *See, e.g., Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433, 437-39 (D.C.Cir.1947) (explaining the "demand-commodity formula").

not a matter for the slide-rule. It involves judgment on a myriad of facts." *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, 65 S.Ct. 829, 833, 89 L.Ed. 1206 (1945). Although the relevant technology has changed since *Colorado Interstate Gas*, the point that "[r]ate-making is essentially a legislative function," *id.*, has not. Our task, then, is not to determine whether MFV rate design is superior to SFV rate design, but merely to determine whether FERC has "made a reasoned decision based upon substantial evidence in the record" in departing from MFV rate design. *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C.Cir.1992).

Initially, we note that the PUCs have mischaracterized FERC's decision to depart from MFV rate design. As FERC notes in its brief, "modifying pipeline rate design to promote competition is nothing new." The switch from MFV rate design to SFV rate design does not represent a reversal in ratemaking policy. FERC simply ordered a reallocation of fixed costs in pipeline rate design. The fact that the old system was labeled "MFV" and the new system "SFV" does not mean that the new system represents a radical departure from precedent. Rather, the change in Order No. 636 is simply one more adjustment, albeit a significant one, in a decades-long series of adjustments in rate design. *See, e.g., Canadian River Gas Co.*, 3 FPC 32 (1942), *aff'd, Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 65 S.Ct. 829, 89 L.Ed. 1206 (1945); *Mississippi River Fuel Corp.*, 4 FPC 340 (1945), *aff'd in part and remanded, Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433 (D.C.Cir.1947); *Atlantic Seaboard Corp.*, 11 FPC 43 (1952); *State Corp. Comm'n v. FPC*, 206 F.2d 690 (8th Cir.1953), *cert. denied*, 346 U.S. 922, 74 S.Ct. 307, 98 L.Ed. 416 (1954); *Fuels Research Council, Inc. v. FPC*, 374 F.2d 842 (7th Cir.1967); *United Gas Pipe Line Co.*, 50 FPC 1348 (1973), *reh'g denied*,

51 FPC 1014 (1974), *aff'd sub nom. Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176 (D.C.Cir.1975); *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578 (D.C.Cir.1979); *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir.1986) (*NIPSCO*).

Like past changes in rate design, FERC initiated the departure from MFV in response to changing market conditions. Specifically, the agency determined that continued adherence to MFV rate design would "inhibit the goal of the development of a competitive, national gas market and, therefore, . . . [would] not comport with the goals set forth" in Order No. 636. Order No. 636, ¶ 30,939, at 30,433. For various reasons, pipelines prior to Order No. 636 had differing amounts of fixed costs in their commodity and usage charges. As FERC determined, "[t]his situation . . . can hinder competition between gas sellers at the wellhead because competition is not based on the seller's costs and therefore on their ability to compete directly with each other." *Id.*; *see also supra* Part IV.A.1.

The PUCs' objection that FERC has used MFV pricing in the past does not come to terms with the fact that the natural gas industry is being reorganized at Congress' direction and that FERC is now attempting to structure the rate design system to favor the development of a nationwide, competitive natural gas marketplace. FERC reasonably determined that, "because in its current assessment of the prevalent economic and market circumstances it believes the goal of achieving an efficient, national gas market is the factor that should control the selection of the appropriate rate design method," Order No. 636- A, ¶ 30,950, at 30,605, its departure from the strict terms of MFV rate design as approved in 1986 was justified. Similarly, the PUCs' reliance on the practices in the oil pipeline industry is

misplaced. The same goals, problems, and solutions may or may not apply to oil pipelines,[81] but there is no requirement that rate design function in the same manner across both industries. Finally, as FERC stresses, the Order No. 636 regime permits parties to seek approval of non-SFV rate design methods in individual rate proceedings. *See* Order No. 636, ¶ 30,939, at 30,434; Order No. 636-A, ¶ 30,950, at 30,605. For all these reasons, we hold that FERC has supported its determination to abandon MFV rate design with substantial evidence in the record.

2. *FERC's choice of SFV rate design*

Several petitioners raise challenges to FERC's determination that SFV is the appropriate rate design method for the natural gas market. The LDCs argue that the commodity and usage charges under SFV rate design will not reflect differences in transportation costs for different pipelines, thus sending improper price signals to gas purchasers. The PUCs argue that under SFV rate design, pipelines will recover all of their fixed costs through reservation and demand charges and will hence have no incentive to maximize pipeline throughput. The Electric Generators argue that FERC failed to consider adequately an alternative rate design method proposed by Arizona Electric. Finally, the Small Distributors argue that the switch to SFV will result in an increase in gas prices at the wellhead, and that FERC has failed to demonstrate that such an increase is necessary to assure an adequate supply of gas. As

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81. For example, one crucial difference between rate design for oil pipelines and gas pipelines is that oil pipelines do not impose separate reservation and demand charges, thus occasioning no design problem analogous to the one the Commission confronted here. *See Association of Oil Pipe Lines v. FERC*, 83 F.3d 1424 (D.C.Cir.1996).

we noted in the previous section, our task is not to determine whether SFV is in fact the best rate design method available, but merely to determine whether FERC can support its choice with substantial evidence in the record.

a. *LDCs' claim*

The LDCs[82] claim that the switch to SFV rate design will undermine gas purchasers' ability to make economically efficient choices of gas suppliers because the per unit gas price they face from a supplier will not reflect the distance which the gas must travel over a pipeline to reach the customer. In consequence, a gas purchaser might choose to buy from supplier A, who transmits gas over pipeline AA for a distance of 1,000 miles, when the economically efficient outcome would have been for the purchaser to buy from supplier B, who transmits slightly more expensive gas over pipeline BB for a distance of only 500 miles. The LDCs' analysis, however, overlooks two important facts. First, as FERC points out, "the variable cost of transportation — basically the cost of fuel for pipeline compressors," will still be included in the commodity and usage charges. So gas purchasers will receive the proper signal regarding the actual differences among suppliers in variable transportation costs. *See* Order No. 636, ¶ 30,939, at 30,437. Furthermore, gas purchasers will still take differences in fixed transportation costs into account, because those cost components will be included in the reservation and demand charges. *Id.* As FERC notes, "[l]ocational advantages will continue to matter, because long-distance transportation generally will require more facilities, and thus will have higher fixed costs, than shorter-distance arrangements."

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82. LDCs presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co.

The LDCs argue, citing *Catalano, Inc. v. Target Sales, Inc.*, 446 U.S. 643, 648 n. 10, 100 S.Ct. 1925, 1928 n. 10, 64 L.Ed.2d 580 (1980) (*per curiam*), that FERC's removal of transportation costs from per unit charges at the supplier level amounts to "base point pricing," which, they argue, "would be [a] per se violation [ ] of the antitrust laws," if done by agreement among private parties to fix the price of transportation added to the price of products. While we have concluded that FERC's response to this argument is adequate, we further note that the base point pricing cases have involved private agreement in otherwise unregulated markets, and commodities such as cement, expensive to transport as contrasted with natural gas, a product which not only is the subject of pricing regulation but also is extraordinarily inexpensive to transport over pre-existing pipelines. *Cf. FTC v. Cement Institute*, 333 U.S. 683, 697, 68 S.Ct. 793, 801, 92 L.Ed. 1010 (1948). We accordingly reject the LDCs' challenge to FERC's decision to implement SFV rate design.

b. *PUCs' claim*

The PUCs argue that the switch to SFV rate design "will frustrate, rather than promote, the goals of maximizing efficiency and competition." Their complaint centers on the claim that because pipelines under SFV rate design will be able to collect all their fixed costs, including return on investment and taxes, in the demand charge, they will have no incentive to assure that gas actually flows through the pipeline under firm service arrangements. That is, because a pipeline will recover no fixed costs or return on investment through the commodity or usage charge, it will have no incentive to transport any gas.

FERC recognized this potential incentive problem in Order No. 636, but determined that "the pipelines will now have much

less influence on the use of their systems because they are transporting gas to, rather than selling gas at, the city-gate." Order No. 636, ¶ 30,939, at 30,436. Accordingly, "[t]ransportation volumes will mainly be a function of the needs of gas purchasers and the prices offered by gas sellers in the production areas." *Id.* In any case, "the goals to be accomplished via SFV outweigh generally the goal of allocating fixed costs to annual throughput." Order No. 636-A, ¶ 30,950, at 30,606. We find these explanations sufficiently convincing to meet the substantial evidence standard for rate design in the face of the PUCs' incentive argument.

c. *Electric Generators' claim*[83]

The Electric Generators argue that FERC failed to consider adequately the demand-responsive volumetric charge system proposed by Arizona Electric Power Cooperative, Inc. (AEPCO), as an alternative to SFV rate design. They claim that AEPCO's proposed system does a better job of rationing scarce capacity during peak demand. However, FERC correctly counters that the fact that AEPCO may have proposed a reasonable alternative to SFV rate design is not compelling. The existence of a second reasonable course of action does not invalidate an agency's determination. *See Cities of Batavia v. FERC*, 672 F.2d 64, 84 (D.C.Cir.1982) ("[T]he billing design need only be reasonable, not theoretically perfect."). Although an administrative agency must respond to "comments which, if true, . . . would require a change in an agency's proposed rule," *American Mining Congress v. EPA*, 907 F.2d 1179, 1188 (D.C.Cir.1990) (internal quotation marks and citations omitted), FERC has met that standard as to AEPCO's proposal. FERC noted the generator's concerns, but concluded that its own plan would better avoid

83. Arizona Electric Power Cooperative, Inc., sponsors this argument.

the distorting influences on the gas market experienced during MFV ratemaking. Order No. 636-A, ¶ 30,950, at 30,606-07. Though AEPCO and FERC each briefly debate the merits of the two proposals, we see no basis for voiding FERC's ruling, which appears based on substantial evidence in the record.

d. *Small Distributors' and Municipalities' claim*[84]

The Small Distributors and Municipalities argue that the effect of SFV rate design is to increase gas prices at the wellhead. They further claim that FERC failed to demonstrate that such an increase is necessary to assure adequate supply. FERC points out that this argument is not properly before the court because petitioners did not raise it in the administrative proceedings in their request for rehearing of Order No. 636. As we noted earlier, *see supra* Part IV.A.2, 15 U.S.C. § 717r(b) (NGA § 19(b)) clearly states that "[n]o objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do." *See also ASARCO*, 777 F.2d at 773-75 (elaborating on the significance of the § 717r(b) requirement that the objection be raised before FERC). Finding no mention of this price increase objection in the petitioner's rehearing request, and hearing no explanation by the petitioner of a reasonable ground for this omission, we conclude that the price increase objection is not properly before the court and decline to reach it.

3. *Regulatory Flexibility Act*

The Regulatory Flexibility Act, 5 U.S.C. §§ 601-612 (RFA), requires that an agency conduct a regulatory flexibility analysis

84. The National Association of Gas Consumers supports this argument.

(or "small entity impact analysis") for any rule that will have a "significant economic impact on a substantial number of small entities." 5 U.S.C. § 605(b). The PUCs argue that the RFA required that FERC perform a small entity impact analysis for Order No. 636 because of its significant economic effect on LDCs. However, in *Mid-Tex Elec. Co-op., Inc. v. FERC*, 773 F.2d 327, 340-43 (D.C.Cir.1985), we conducted an extensive analysis of the RFA provisions governing when a regulatory flexibility analysis is required and concluded that no analysis is necessary when an agency determines "that the rule will not have a significant economic impact on a substantial number of small entities that are subject to the requirements of the rule." *Id.* at 342 (emphasis added). FERC has no jurisdiction to regulate the local distribution of natural gas. 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply to . . . the local distribution of natural gas or to the facilities used for such distribution."). Accordingly, the allegation that Order No. 636 may have a significant economic impact on LDCs (an assertion FERC disputes) is not sufficient to trigger the mandate of the RFA. FERC had no obligation to conduct a small entity impact analysis of effects on entities which it does not regulate.

C. *FERC's Discretion to Adopt Mitigation Measures*

1. *Background*

FERC recognized that the adoption of SFV rate design could result in cost shifting among pipeline customers because of their differing load factors. Order No. 636, ¶ 30,939, at 30,435; Order No. 636-A, ¶ 30,950, at 30,601-03; Order No. 636-B, ¶ 61,272, at 62,015-16. The adoption of SFV will, at least arguably, shift costs to low load factor customers in two ways: first by removing all fixed charges from the usage charge; and second by

measuring usage solely based on peak demand, rather than annual usage. To elaborate, a low load factor customer transports most of its gas during the winter heating season; therefore, its average daily usage of its capacity entitlement is significantly below its usage on a peak day. As a result of this demand structure for low load factor customers, they usually pay proportionately more in reservation and demand fees than do high load factor customers. This result follows logically when reservation fees are constant throughout the year for a high and a low load factor customer who each have the same capacity entitlement. The low load factor customer purchases a lower annual volume of gas; hence, a larger proportion of its payments to the pipeline are made up of reservation fees. The existence of this phenomenon means that, once the pipeline has switched to SFV, the low load factor customers will pay a higher share of pipeline fixed costs than they did under MFV. Under MFV, low load factor customers could escape some of the fixed costs by not purchasing their full entitlement of gas because the per unit price of the gas contained some fixed costs. Additionally, under SFV, FERC has determined that the reservation and demand charges will no longer vary with annual usage, as they did under MFV. Order No. 636-A, ¶ 30,950, at 30,599.

To offset these cost shifts likely to result from Order No. 636, FERC adopted several mitigation measures. First, it required that pipelines "use some measure, such as seasonal contract quantities," in calculating reservation and demand fees when the switch to SFV rate design "causes significant cost shifts" to individual customers. Order No. 636-A, ¶ 30,950, at 30,599. If, even after the seasonal adjustments, the switch to SFV still resulted in a ten percent or greater rate increase under SFV for a particular customer class, FERC required that the pipeline phase in SFV rate design over four years for that

customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603-04. FERC also sought to retain the protection for small customers that the old regime offered by requiring all pipelines that offered service under a one-part volumetric rate at an imputed load factor on May 18, 1992, to offer transportation service under a similar rate structure to all customers who were eligible on that date for such an arrangement. Order No. 636-A, ¶ 30,950, at 30,600; Order No. 636-B, ¶ 61,272, at 62,018-22. We will label this mitigation measure the "small customer discount."

Petitioners bring several different challenges to the adoption of these mitigation measures and to various aspects of their implementation. We now consider each of these challenges.

2. *Justifications for mitigation measures*

The high load factor LDCs object to FERC's requirement of a small customer discount and to the use of seasonal adjustments for low load factor customers. They argue that the small customer discount results in high load factor customers having to pay higher unit charges than would be the case without the requirement. They also maintain that the use of seasonal adjustments for low load factor customers eliminates the incentive for these customers to flatten their demand over the course of the year. Seasonal adjustments also allegedly penalize high load factor customers for their foresight in using storage and other peak shaving tools in winter months to flatten their demand. The LDCs claim that the higher charges to high load factor customers resulting from these mitigation measures "unduly discriminate against residential customers of high load factor LDCs and give preferential treatment to customers" of low load factor LDCs in violation of NGA § 5(a).

FERC responds to the LDCs' claims by stressing that the effect of the mitigation measures is to preserve as much of the status quo as possible with respect to cost allocation. The intervenors point out that the LDCs' attack on the mitigation measures improperly assumes that SFV rate design is a baseline from which any mitigation measures should be judged. Both FERC and the intervenors are correct. The LDCs' claim of "discrimination" is based on the assertion that they, and ultimately their customers, will have to pay a larger share of fixed costs than they would pay without the mitigation measures. But the LDCs have no sustainable argument for why this should invalidate the measures. There is no "neutral" or inherently "fair" allocation of fixed costs, as the history of rate design amply demonstrates. The LDCs assume that allocating fixed costs according to a straight SFV methodology is the "fair" way of doing things, a curious position in light of the LDCs' opposition throughout these proceedings to the adoption of SFV rate design. But there is no "fair" baseline from which to judge a particular cost allocation scheme.

In any case, FERC correctly points out that it has long rejected the position that fixed costs should be allocated solely on the basis of peak day demand, as would apparently result under a straight SFV system with no mitigation measures. The courts have concurred in FERC's rejection of such a regime. *See NIPSCO*, 782 F.2d at 742 ("[T]he Commission long ago with judicial approval rejected the argument that fixed costs should only be allocated and recovered solely on the basis of peak day demands."). As for the LDCs' argument that the seasonal adjustments remove the incentive for low load factor customers to flatten their demand throughout the year, we note that this incentive is greatly magnified under a "pure" SFV system as compared to an MFV system. Under MFV, the low

load factor customers could have avoided part of the fixed costs during periods of low demand because part of the per unit gas charge included fixed costs. "Reducing" the stronger incentive to flatten demand that would otherwise exist under SFV is not problematic because, as we have just explained, a pure SFV system is not a proper baseline from which to judge the appropriateness of mitigation measures.

The same reasoning applies to the LDCs' claim that the mitigation measures unfairly penalize those LDCs whose foresight led them to invest in peak-shaving facilities before Order No. 636. The mitigation measures only look like an unprecedented subsidy flowing from high load factor customers to low load factor customers when one compares the Order No. 636 regime to a straight SFV regime with no mitigation measures at all. Once again, a strict SFV regime is not the proper baseline. When one compares the Order No. 636 system with the pre-Order No. 636 system, in which low load factor customers escaped part of their share of fixed costs by reducing purchases in low demand periods, the mitigation measures make sense in light of FERC's goal of avoiding sudden and shocking departures from the status quo with respect to cost allocation. In short, low load factor customers avoided some fixed costs in low demand periods before Order No. 636, and they are still avoiding some fixed costs in low demand periods after Order No. 636. LDCs which adopted peak- shaving techniques are no worse off than they were before Order No. 636. It is therefore improper to say that FERC has "penalized" them.[85]

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85. The LDCs also argue that under the Order No. 636 regime, low load factor customers have several new means of adaptation at their disposal and are not in need of mitigation measures. However, as FERC points out, none of the LDCs raised this argument in their rehearing petitions before the Commission. They are accordingly barred from raising it in this court under 15 U.S.C. § 717r(b). *See supra* Part IV.A.2.

There being no neutral standard or baseline to guide the court in evaluating mitigation measures, the only relevant question is whether FERC has made a reasonable allocation of fixed costs supported by substantial evidence. Considering the Order No. 636 series as a whole and bearing in mind FERC's regulatory goals and history, we are convinced that FERC has supported its adoption of mitigation procedures with substantial evidence. We now turn to the various challenges raised by petitioners to specific aspects of the mitigation measures.

3. *Non-permanence of mitigation measures*

As we noted above, *see supra* Part IV.C.1, FERC ordered that under certain circumstances, pipelines must phase in SFV rate design over four years for a customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603- 04. The Small Distributors and Municipalities[86] contend that, rather than phasing in new rates, FERC should have adopted permanent mitigation of their rates. They argue that "[u]nreasonable rates do not become just and reasonable by phasing them in over a four-year period. Mitigation is no less vital four years later when the Commission's four-year 'remedy' expires." But FERC responds that the purpose of the four-year phase in period was not to protect the customer class from cost shifting altogether, but merely to avoid the shock of allowing it to happen all at once. FERC's response is perfectly sensible, and we hold that the Commission has justified under the substantial evidence standard the four-year phase in period in the circumstances in which Order No. 636 requires it.

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86. Distributors joining in this argument include the American Public Gas Association and the National Association of Gas Consumers.

Appendix A

4. *Impact on pipeline rate of return*

The PUCs argue that FERC should have reduced the pipelines' rate of return because the pipelines will be able to recover all of their fixed costs and return on investment through demand and reservation charges instead of facing the uncertainty of recovering a portion of their fixed costs and return through gas sales throughout the year. *See supra* Part IV.B.2.b (describing reduced pipeline uncertainty under SFV rate design). Specifically, the PUCs contend that FERC should have followed its decision in *Transcontinental Gas Pipe Line Corp.*, 56 FERC ¶ 61,037, *modified in part*, 57 FERC ¶ 61,331 (1991), 62 FERC ¶ 61,221 (1993), 64 FERC ¶ 61,099 (1993), *rev'd in part on other grounds*, *Transcontinental Gas Pipe Line Corp. v. FERC*, 54 F.3d 893 (D.C.Cir.1995), and imposed a 25 basis point reduction in pipelines' return on equity to reflect the lower risk under SFV rate design. However, FERC stresses that it deferred any such adjustments in rates of return to the individual restructuring proceedings in light of the fact that "pipeline risk is a matter for pipeline-specific analysis in light of all risks." Order No. 636, ¶ 30,939, at 30,437. As we have said before, setting a rate of return is "an intensely practical affair requiring the conversion of inexact data into exact rates or limits upon rates." *Matson Navigation Co. v. Federal Maritime Comm'n*, 959 F.2d 1039, 1043 (D.C.Cir.1992) (citations and internal quotation marks omitted). Nothing in the law requires that FERC take a "shotgun" approach to the problem of decreased pipeline risk by ordering an across-the- board rate reduction, much less that the court do so. We note in this regard that *Transcontinental* Gas, the decision upon which petitioners rely, was itself an individual pipeline rate making decision. FERC easily meets its burden of supporting its decision to defer rate of return adjustments to individual restructuring proceedings.

5. *Individual customer vs. customer class*[87]

FERC required that pipelines use measures such as seasonal contract adjustments to avoid significant cost shifting for individual customers. If, after application of these mitigation measures, the use of SFV "still results in a 10 percent or greater increase in revenue responsibility for any historic customer class," then the pipelines are required to phase in the increase over four years. Order No. 636-B, ¶ 61,272, at 62,016 (emphasis added). The Pipeline Petitioners argue that the mitigation measures short of four-year phase in should also have been required on the basis of customer class rather than on the basis of SFV's effects on individual customers.

In deciding to base the initial mitigation measures on SFV rate design's effects on individual customers rather than customer class, FERC cited several recent decisions in individual pipeline restructuring proceedings. *Id.* at 62,016 n. 140. However, these rulings simply implement Order No. 636 and order studies on the effect of SFV rate design on individual customers, anticipating the adoption of mitigation measures on a customer-by-customer basis. But relying on these orders as a justification for the customer-by-customer basis would be a classic case of bootstrapping, amounting to a conclusion that Order No. 636 properly requires the customer-by-customer approach since several decisions implementing Order No. 636 take that approach. Nothing in any of the decisions justifies the basic determination in favor of the individual customer approach. Significantly, FERC cites no other support for its decision in Order No. 636-B to favor the individual customer approach.

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87. Williston Basin Pipeline Company seeks review of this issue.

The Pipeline Petitioners also raise an important question about the danger of the individual customer approach with respect to pipeline cost recovery:

> [R]ates are determined on the basis of costs incurred and billing quantities during a specified test period. While it is reasonable to expect that the actual billing quantities of all customers in each class during the period the rates are in effect will approximate those experienced by the class during the test period, it is likely that individual customers may experience larger variances in billing quantities. The establishment of rates on a customer-by-customer basis therefore increases the risk that a pipeline will fail to collect its total costs during the period in which rates are in effect.

Pipeline Petitioners' Brief at 27. They also argue that FERC's order fails to take into account potential customer cost reductions under Order No. 636 that are not directly related to the switch to SFV rate design, and that the individual customer method "increases the likelihood for discrimination in rates to similarly situated customers in violation of Sections 4 and 5 of the Natural Gas Act."

FERC has provided, in response to our request at oral argument, several citations to Order Nos. 636-A and 636-B which supposedly explain FERC's decision to implement the initial mitigation measures on a customer-by-customer basis. However, after examination of these citations, we conclude that the discussions cited on this question are ambiguous at best and

incomplete at worst. FERC has failed to address adequately, in either the Order No. 636 series or in its brief, the Pipeline Petitioners' objections which we have outlined above. Because, as previously noted, the Commission has failed to provide any reasoned justification for its decision on this issue, and because the petitioners' objections raise serious questions about the appropriateness of FERC's ruling, we conclude that the Commission has failed to support its decision on this issue with substantial evidence. We therefore remand to the Commission the question of whether the initial mitigation measures should be implemented on the basis of customer class for further examination.

6. *Discounts for former customers of downstream pipelines*

In requiring a continuation of the pre-Order No. 636 small customer discounts, FERC only mandated that downstream pipelines offer the discount to the class of customers eligible for it on May 18, 1992. But the Small Distributors[88] argue that FERC should have required upstream pipelines to provide the discounts to any customers of downstream pipelines who received the discounts on May 18, 1992. The downstream pipeline customers were indirect customers of the upstream pipelines under the old regime and now are direct customers of these upstream pipelines. The Small Distributors argue that these former downstream pipelines customers "are now indistinguishable from the upstream pipeline's other small customers, with whom they compete directly for markets." FERC's failure to account for this fact results in "undue discrimination between similarly-situated small customers on

88. The East Tennessee Group, the National Association of Gas Consumers, and the Tennessee Valley Municipal Gas Association support this argument.

the same pipeline solely on the basis of whether they used to be served through a downstream pipeline prior to Order [No.] 636." Although FERC did indicate in Order No. 636-B that the former downstream pipeline customers' need for discounts should be examined in individual restructuring proceedings, the Small Distributors contend that it is unfair and unreasonable to make them demonstrate such a need in restructuring proceedings when that need has already been presumed for other small customers.

The Small Distributors raise excellent points. FERC's failure to counter them with anything but its insistence that former downstream customers can raise their need for small customer discounts in upstream pipeline restructuring proceedings (perhaps they can, although the Small Distributors dispute the effectiveness of such a course of action), does not address the core of the Small Distributors' argument. FERC has made an arbitrary distinction between former indirect small customers of upstream pipelines (who are now direct small customers) and small customers who have always been direct customers of the same pipelines. Because FERC has not supported this distinction with substantial evidence in the record, we remand this issue to the Commission for further consideration of whether or not the small customer benefits should be made available to the former downstream small customers.

7. *Triennial rate review*

In Order No. 636-A, FERC abandoned the requirement of triennial rate review, which it had formerly imposed on many pipelines in exchange for granting the pipelines certain powers over their rates. FERC explained that the only reason it had formerly required triennial rate review was because of the power it had granted the pipelines. Specifically, under the purchased

gas adjustment (PGA) regulatory scheme, participating pipelines had discretion to change the gas supply cost element of their rates. In exchange for this ability, "pipelines had to agree to a reexamination of all their costs and rates at three year intervals to assure that gas cost increases were not offset by decreases in other costs." Order No. 636-A, ¶ 30,950, at 30,671; *see also* 18 C.F.R. § 154.303(e) (laying out triennial rate review requirement). Under the Order No. 636 regime, pipelines have no special rate adjustment mechanism comparable to the PGA scheme, so FERC concluded that triennial rate review was unnecessary. In Order No. 636-B, FERC even raised the question of whether it had the discretion to order triennial rate review under the Order No. 636 regime, noting that "there are limits to the authority of the Commission to require pipelines to periodically justify their existing rate levels." Order No. 636-B, ¶ 61,272, at 62,044-45 (citing *Public Serv. Comm'n v. FERC*, 866 F.2d 487 (D.C.Cir.1989) (*PSCNY*) (holding that requiring periodic filings under NGA § 4 is beyond FERC's statutory authority)).

The LDCs[89] argue that FERC should not have abandoned triennial rate review. First, they claim that FERC "ignored that the market- based sales rate authority granted pipelines under Order [No.] 636 is a 'special rate adjustment mechanism' " justifying a periodic rate review. In any case, they argue that FERC certainly does have the authority to impose triennial rate review under the Order No. 636 regime. In their view, PSCNY simply means that "FERC cannot impose [a periodic filing] requirement except as a condition of some other benefit

89. Associated Gas Distributors, Consolidated Edison Company of New York, Inc., Illinois Power Co., and Peoples Natural Gas Co. present this argument. Supporting intervenors are PECO Energy Co. and Washington Gas Light Co.

voluntarily accepted by the pipeline." Because Order No. 636 conferred several benefits on pipelines, the LDCs contend that FERC's failure to attach periodic rate review to at least one of those benefits was unjustified. FERC, however, contends that the "benefits" to pipelines cited by the LDCs are not nearly so certain: "there is no reason to believe that by allowing a pipeline to sell gas at market-based rates, rather than regulated cost-based rates, Order No. 636 makes it more likely that rates for unbundled transportation service will become unjust and unreasonable."

The PUCs also argue in favor of retaining triennial rate review, restating the LDCs' argument that FERC has conferred a benefit on pipelines by instituting SFV rate design and can accordingly require periodic rate review. They also point out that, under SFV, as long as fixed costs continue to decline, pipelines will have no incentive to file NGA § 4 rate cases since they will be recovering all of their fixed costs through reservation and usage fees. Consumers will then be left with an NGA § 5 complaint as their only option for protecting themselves, but a § 5 complaint is less satisfactory than a § 4 rate case because under § 5 the burden is on the complainant to establish the unjustness or unreasonableness of the rate. Also, § 5 relief is prospective only; § 4 relief can encompass a refund order. FERC responds that "traditional ratemaking tools are available to take account of long-run declining costs, and a three-year review [is] unnecessary."

FERC's position that it lacks authority to impose triennial rate review is quite strong. The LDCs' claim that the market-based sales authority granted to pipelines is a "benefit" to which triennial rate review may be attached rings hollow in light of the fact that pipelines are leaving the gas sales business in favor

of gas transportation under Order No. 636. Furthermore, whatever the benefits of SFV rate design to pipelines, they are not benefits voluntarily accepted by the pipelines and so cannot be the basis for the imposition of periodic rate review. *See PSCNY*, 866 F.2d at 492 (noting that FERC's authority to impose triennial rate review in the PGA context "obviously rests on pipeline consent" to triennial rate review in exchange for automatic PGA adjustment authority). In any case, in the presence of these serious doubts about FERC's authority to impose periodic rate review in the Order No. 636 context and in view of the alternative procedures available to the Commission for ensuring reasonable rates, we hold that petitioners have failed to show that FERC has not supported its decision to drop triennial rate review with substantial evidence.

V. Transition Costs

In this part of the opinion, we briefly review the history behind the transition cost issue and consider each of the petitioners' challenges to FERC's treatment of transition costs.

A. *Background to Transition Costs*

1. *Order No. 436 and its successors*

Order No. 436 began the natural gas pipeline industry's transition from its historic role as gas merchant to gas transporter. The Order authorized interstate gas pipelines to convert to blanket-certificated "open-access" transportation service. *See supra* Part I.B. In exchange, however, customers of those pipelines that did convert were permitted both (1) to convert their firm sales obligations into firm transportation contracts and also (2) to reduce their obligations to purchase gas from the

pipelines. Pipeline customers in large numbers exercised their right under the Order to buy less gas from the pipelines, and secured gas supplies from less expensive sources. The pipelines themselves were then left with massive obligations to purchase high-priced gas at the wellhead:

> [T]he conditions under which the NGPA began to relax wellhead price controls — namely acute gas shortage and sharply rising prices for alternative fuels — tended to divert pipeline attention from the hazards of incurring long-term obligations to buy high-priced gas. Under pressure from the Commission, the pipelines had typically purchased gas under contracts for very long terms. Besides incorporating high prices (and provisions for escalation upward), the contracts commonly included "take-or-pay" provisions, requiring the pipeline to pay for some specified percentage, say 75%, of the deliverable gas even if it took less. While usually subject to recoupment later, and while a perfectly natural allocation of risk between producer and purchaser, the take-or-pay provisions effectively committed the pipelines to high gas costs in what by 1982 proved to be a time of falling prices, both for competing fuels and for substitute supplies of gas not covered by contract.

AGD I, 824 F.2d at 995-96 (citations omitted) (emphasis added).

Thus arose the "take-or-pay" liabilities addressed by the

Commission in Order No. 436 and its successors, as well as by this court in a variety of opinions. *See supra* Part I.B. Specifically, because most customers could purchase gas more cheaply from other sources, pipelines essentially were unable to pass through the costs of their own supply obligations. With purchases sharply reduced, pipelines owed massive "take-or-pay" liabilities to gas producers, which they had to either "buydown" — *i.e.*, reduce — or "buyout" — *i.e.*, eliminate. In Order No. 436, the Commission refused to set a general policy on whether or how pipelines could attempt to recover these costs. We vacated and remanded the Order, concluding that, in this regard, it was not based on reasoned decisionmaking, primarily because it appeared to grossly underestimate the financial impact of take-or-pay liability on pipelines. *Id.* at 1021- 30. Of great concern to the court was the likelihood that even higher gas prices would simply cause more customers to switch suppliers, thereby exacerbating the take-or-pay crisis. This cycle of ever increasing prices and ever shrinking customer base — a phenomenon that petitioners label the "death spiral" — made it very unlikely that the pipelines would in fact recoup their take-or-pay liabilities absent some mechanism for separately passing those costs through to their customers.

In subsequent proceedings, the Commission adopted and this court approved various measures designed to address that concern and allow pipelines to pass through some of their take-or-pay liabilities to a broader range of customers. *See supra* Part I.B. Most pertinent to our analysis here, under Commission policy, a pipeline could agree to absorb between 25% and 50% of its take-or-pay costs in exchange for the right to bill customers an equal share through a fixed charge, and recover the remaining amount through a volumetric surcharge based on total throughput. Customers, and in turn the consuming public,

ultimately reimbursed pipelines for approximately $6.4 billion in take-or-pay costs, while the pipelines themselves absorbed $3.6 billion.

2. *Order No. 636 and petitioners' challenges*

After Order No. 436, all of the major interstate pipelines converted to open-access transportation. Not all customers on those pipelines, however, exercised their right to unbundle their sales agreements and reduce their gas purchase obligations. Several years later in Order No. 636, the Commission mandated unbundling and authorized sales customers to reduce their pipeline gas purchases. When customers exercised that right and secured gas supplies from other sources, the pipelines once again incurred substantial take-or-pay liabilities; though the Commission labeled these liabilities "gas supply realignment costs" in Order No. 636, they arose from the same type of producer- pipeline contract provisions as the "take-or-pay" costs considered in Order No. 436. *Cf.* Order No. 636-A, ¶ 30,950, at 30,649 n.466 ("Any costs that would qualify for recovery as GSR costs could be filed for recovery under [the successor to Order No. 436,] Order No. 528.").

In allocating recovery of GSR costs, however, the Commission adopted a policy more advantageous to the pipelines. Instead of refusing to establish a mechanism for pipelines to recover their take-or-pay costs, as it originally had in Order No. 436, FERC authorized pipelines to bill their customers separately for 100% of their GSR costs. This policy was, in fact, a substantial change from even Order No. 500, which permitted pipelines to surcharge their transportation customers for take-or-pay costs only if they agreed to absorb between 25 and 50% of those costs. The Commission set forth

the mechanisms available to pipelines under Order No. 636 as follows:

> . . . The Commission will permit pipelines full cost recovery of prudently incurred gas supply realignment costs deemed to be eligible under this rule. To recover those costs, a pipeline will be permitted to use either a negotiated exit fee, or a reservation fee surcharge recoverable from Part 284 firm transportation customers.
>
> Under this rule, a firm entitlement holder has options as to how to react to gas supply realignment costs: it may remain a sales customer of the pipeline; otherwise, it may take an assignment of the pipeline's existing contracts or pay an exit fee/reservation fee surcharge for costs approved by the Commission.

Order No. 636, ¶ 30,939, at 30,458. On rehearing, FERC modified this ruling somewhat, and required pipelines to bill 10% of their GSR costs to interruptible transportation customers. *See infra* Part V.E.3.b.2.

Pipelines also face three other types of significant transition costs under Order No. 636: (1) unrecovered gas costs or credits remaining in the purchased gas adjustment (PGA) account when a pipeline terminates its PGA mechanism; (2) costs of pipeline assets (such as storage facilities) currently used to provide bundled sales service which are not directly assignable to customers of the unbundled services ("stranded costs"); and (3)

costs for equipment required to physically implement the rule ("new facility costs"). Order No. 636, ¶ 30,939, at 30,457. FERC determined in Order No. 636 that pipelines would generally be allowed to recover 100% of these costs. *Id.* at 30,457-60.

Petitioners raise several challenges to FERC's treatment of transition costs. First, they claim that FERC erred in allowing pipelines to recover 100% of their stranded costs, arguing that such recovery violates applicable legal standards. Second, they contend that FERC failed to adequately address the problem of "LDC bypass," which occurs when large industrial customers bypass LDCs, thereby avoiding transition costs properly attributable to them. Third, they oppose Order No. 636's passthrough of above-market prices paid by pipelines for synthetic natural gas from the Great Plains Gasification Plant. Finally, they challenge in several respects FERC's treatment of GSR costs.

B. *Stranded Costs and the "Used and Useful" Doctrine*

A separate class of Order No. 636 transition costs are "stranded costs," which are those "incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services." Order No. 636, ¶ 30,939, at 30,460. To be denominated "stranded," an investment (1) must have been prudently made, Order No. 636-A, ¶ 30,950, at 30,662, but (2) must be no longer "used and useful" after Order No. 636, Order No. 636-B, ¶ 61,272, at 62,041. Examples include upstream pipeline capacity for which a downstream pipeline cannot find a buyer, and storage capacity that a pipeline no longer needs when the volume of its sales service shrinks. Order No. 636, ¶ 30,939, at 30,460. According to the Commission, pipelines can recover their stranded costs

in NGA § 4 rate filings. *Id.*; *see also* Order No. 636-B, ¶ 30,950, at 62,042 ("The Commission will allow pipelines to make limited section 4 filings to recover . . . the costs of stranded facilities that are currently incrementally priced . . . . However, pipelines must file to recover the costs of most, if not all other stranded facilities in general section 4 rate proceedings.").

The PUCs challenge the Commission's ruling, *see* Order No. 636-B, ¶ 61,272, at 62,041, that pipelines may recover 100% of their stranded costs. Their presentation is straightforward: items that are not currently "used and useful" may not be included in a utility's rates. In support, the PUCs invoke the Commission's statement in *New England Power Co.*, 42 F.E.R.C. ¶ 61,016, at 61,078 (1988), that "[i]n general, the used and useful standard provides that an asset may be included in a utility's rate base only when the item is used and useful in providing service." They also cite to this Court's statement in *Tennessee Gas Pipeline v. FERC*, 606 F.2d 1094, 1109 (D.C.Cir.1979), that "the precept endures that an item may be included in a rate base only when it is 'used and useful' in providing service."

In its brief, the Commission replies along two fronts. First, it contends that the PUCs' objection is premature, given that in Order No. 636, the Commission stated that, in subsequent restructuring proceedings, it would "consider arguments about whether particular facilities are used and useful, or whether the costs should be recoverable as transition costs" in § 4 rate proceedings. Order No. 636-A, ¶ 30,950, at 30,662. Second, the Commission contends that the "used and useful" principle invoked by the PUCs, while generally sound, does not apply to facilities that have been stranded only because of the Commission's own action. In other words, the pipelines should recover on their investments as they would have had Order No. 636 never been promulgated.

While we ultimately affirm the position taken by the Commission in the administrative proceedings, we believe that both the PUCs and the Commission itself may have overlooked a relevant distinction on appeal: the difference between a utility's rates and its rate base. "The rate allowed a utility is the sum of (1) its cost of service, and (2) its rate base multiplied by its rate of return." *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1172 (D.C.Cir.1987) (en banc). "Generally, the rate base is comprised of total capital invested in facilities minus depreciation plus cash working capital. The rate of return, on the other hand, is a weighted average of different rates applied to debt, preferred stock and common stock." *Id.* at 1203 (Mikva, J., dissenting). "Calculation of rate base is a critical step in establishing maximum rates, since the product of rate base multiplied by allowed rate of return is the total sum of money the agency allows to investors in the firm." RICHARD J. PIERCE, JR. & ERNEST GELLHORN, REGULATED INDUSTRIES 102 (3d ed. 1994).

The cases cited by the PUCs, and not challenged by the Commission, stand for the proposition that the items in a utility's rate base generally should currently be used and useful to consumers. As a result, investors generally profit only from those investments that presently benefit consumers. However, that principle does not answer the question whether investments that are not used and useful may nonetheless be included in the utility's rates, *i.e.*, still treated as part of the utility's cost of service.[90]

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90. Our opinion should not be read to prohibit the Commission from applying the "used and useful" principle to issues of recovery through cost of service. Instead, as we explain in our discussion, infra at 117, of *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333 (D.C.Cir.1981), this Court has recognized that the Commission is not required to do so in all instances.

Viewed in this light, the general statement in Order No. 636 that pipelines will recover 100% of their stranded costs still leaves the Commission with a number of options in the § 4 rate proceedings. For example, the Commission could decide that stranded costs should merely be included in the pipeline's cost of service, recoverable through amortization over time. In such an instance, "FERC has already moved somewhat in the direction of balancing competing interests by permitting recovery of the costs of building the plant in the cost of service. Investor interests have not, therefore, been entirely ignored." *Jersey Central*, 810 F.2d at 1192 (Starr, J., concurring). The Commission might also allow the pipeline to recover not only the amortization, but also interest, *i.e.*, the "cost" of the unamortized portion of the investment. The Commission could further decide to include stranded investments in the utility's rate base and thereby generate a profit for investors.

In the administrative proceedings, the Commission assiduously avoided announcing a general standard that would control the manner in which stranded costs may be recovered. Thus, Order No. 636, at 30,460 (emphasis added), states that while "most of the costs of new facilities would be includable in rate base, . . . there is no way of anticipating the nature and amount of the stranded costs, and thus no way at this time of devising an appropriate billing mechanism on a generic basis." Similarly, in Order No. 636-B, ¶ 61,272, at 30,662, the Commission deferred until individual rate cases a party's objection that "costs associated with physical plant that is no longer used and useful . . . should . . . no longer be includable in the rate base."

The PUCs' objection therefore is ripe for review only to the extent that they contend that pipelines should not recover

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100% of their Order No. 636 stranded costs in any fashion. We cannot at this point address the specific question of whether pipelines should be permitted to include stranded costs in their rate base, and thereby receive a profit on the investment, because Order No. 636 adopted no such rule. *Accord, e.g., Columbia Gas Trans. Corp.*, 64 F.E.R.C. ¶ 61,060 (1993) (deferring determination of rate base treatment of stranded cost recovery to § 4 proceeding); *National Fuel Gas Supply Corp.*, 63 F.E.R.C. ¶ 61,291 (1993) (same). In fact, in at least one NGA section 4 rate proceeding, the Commission expressly refused to permit such treatment of stranded costs, explaining:

> Included in [the pipeline's] claim for stranded cost treatment for the production facilities, is a pretax return allowance on the unamortized balance. . . . As discussed above, in order for [the pipeline] to receive stranded cost treatment for these facilities, they must no longer be used and useful. It is long standing Commission policy that when facilities are not used and useful, they do not qualify for rate base treatment. In addition, the recovery of stranded costs is designed to compensate pipelines for out-of-pocket costs that they have no other means of recovering. While the costs of facilities are out-of-pocket costs, equity return and related income taxes are not. Therefore, [the pipeline] should not be allowed a pretax return allowance on the unamortized balance. The Commission will limit [the pipeline's] recovery to interest on the unamortized amount . . . .

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> This is consistent with the way the Commission has treated other costs of a transitional nature that are being amortized over a period of years to reduce the rate impact on customers, *e.g.*, GSR cost amortizations or take-or-pay buyout and buydown cost amortizations. The interest treatment prescribed above adequately compensates the pipeline for the time value of the outstanding unamortized balance, but recognizes the nature of the costs being amortized.

Equitrans, Inc., 64 F.E.R.C. ¶ 61,374, at 63,601 (1993); *cf. National Fuel Gas Supply Corp.*, 71 F.E.R.C. ¶ 61,031, at 61,138 (1995) ("A rate of return on the amount of written down facilities would be inappropriate since this allows a return on facilities that are not economically viable, and may also result in a competitive advantage for the pipeline. The pipeline would, however, be allowed to recover interest on the unamortized portion of its written-down plant over a reasonable amortization period, as this will keep the pipeline whole for the direct cost of its investment in the facilities.").

We reject the PUCs' claim (now properly limited to the argument that the "used and useful" principle per se prohibits pipeline recovery of stranded costs even when merely amortized as part of the cost of service), because it was previously rejected in *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333 (D.C.Cir.1981) (*NEPCO*). In *NEPCO*, we considered "whether FERC's refusal to include project expenditures in the rate base, while allowing their recovery as costs over time, is a valid approach to allocating the risks of project cancellation."

We found such an approach acceptable because, in that case, the Commission's decision was based on substantial evidence and had adequately balanced the interests of investors and ratepayers. *Id.*; *see also Jersey Central*, 810 F.2d at 1183 (rejecting claim that *NEPCO* adopted per se bar to including in rate base items not currently "used and useful"). So long as the Commission's decisionmaking in the individual § 4 proceedings satisfies that standard, it will survive any subsequent challenge brought on "used and useful" grounds.

C. *LDC Bypasses*

Order No. 636 creates new opportunities for large retail customers to bypass LDCs and connect directly to pipelines. Problems of scale and efficiency preclude other customers from taking advantage of such options, however. State regulators and LDCs argued before FERC that it is unfair to force an LDC's remaining customers to pay the transition costs that they contend are fairly allocatable to the departed customers of the LDC. Order No. 636, ¶ 30,939, at 30,461; Order No. 636-A, ¶ 30,950, at 30,658-59. FERC, however, refused to adopt a generic rule to address this problem, determining instead that it would consider requests for relief on a case-by-case basis. The Commission believes that it is reasonable to require that "an LDC seeking relief in a bypass situation . . . show that there is a direct nexus between the bypass and the pipeline, so that the costs it seeks to avoid should be reallocated to the bypassing customer." Order No. 636-A, ¶ 30,950, at 30,659.

The PUCs protest that the burden placed on LDCs of demonstrating the nexus between the bypass and the pipeline is "nearly impossible to meet" because of its specificity. They accordingly argue that the pipeline and the bypassing customer

should have to explain why they shouldn't bear the bypassing customer's share of transition costs. FERC counters that it has "made no statement as to the ultimate burden of proof in such situations" but has left resolution of LDC bypass claims to individual proceedings. However, as noted above, FERC did find it "fair" to require an LDC seeking bypass relief to show a "direct nexus between the bypass and the pipeline." While arguably it may not constitute a "burden of proof" in a technical sense, it does constitute a hurdle of causation which LDCs seeking relief must clear in individual proceedings. Therefore, in contrast to the Intervenors' argument, FERC's "direct nexus" requirement is ripe for review.

We find the PUCs' arguments unpersuasive. First, we note that the "burden" LDCs face in these cases is not "impossible to meet." As FERC notes, it has already made it clear that at least one bypassing customer still must bear its fair share of GSR costs. *See Arcadian Corp. v. Southern Natural Gas Co.*, 67 FERC ¶ 61,176, at 61,538 (1994). Second, FERC reasonably determined that the factual circumstances surrounding LDC bypasses "differ sufficiently that the Commission cannot justify a generic rule [apart from the "direct nexus" requirement] that would be appropriate in all circumstances." Order No. 636-A, ¶ 30,950, at 30,659. We accordingly reject the PUCs' challenges on this issue.

D. *Above-Market Recovery for Great Plains Gas*

The Great Plains Gasification Plant was constructed to convert coal into synthetic natural gas (SNG). In Order No. 636-A, FERC noted that in *Transcontinental Gas Pipe Line Corp.*, 55 FERC ¶ 61,446, *reh'g denied*, 57 FERC ¶ 61,345 (1991) (*Transco*), it had "approved a settlement that provided for a

volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to Transco's obligations to purchase synthetic gas from Great Plains." Order No. 636-A, ¶ 30,950, at 30, 657-58. Several petitioners complained that this arrangement was in substantial conflict with the competition-enhancing purposes of Order No. 636. FERC admitted as much in Order No. 636-A, but determined that the volumetric surcharge "is consistent with the Commission's goal of providing a smooth transition from the prior regulatory environment to the new market-oriented environment." *Id.* at 30,658. Furthermore, FERC followed its reasoning in Transco, concluding that "it is 'reasonable for all [the pipeline's] customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users . . . by increasing the supply of available gas.' " *Id.*

The PUCs challenge FERC's treatment of Great Plains gas, contending that it "conflicts with the goal which forms the heart of Order [No.] 636 — providing consumer access to competitively priced supply." They also cite Commissioner Langdon's partial dissent in Order No. 636, in which he stated that "every comma, word, sentence and paragraph of the order is internally inconsistent" with respect to *Great Plains gas*. Order No. 636, ¶ 30,939, at 30,472 (Langdon, C., concurring in part and dissenting in part). "I fail to see how the [volumetric surcharge] will ultimately benefit the consumer, or transmit accurate pricing signals." *Id.* The PUCs also claim that FERC's decision requires gas consumers to subsidize Great Plains, an outcome the Commission has previously rejected with respect to failed SNG plants.

FERC responds to the PUCs' claims by arguing that

Elizabethtown III, 10 F.3d at 873-74, has already settled this issue. *Elizabethtown III* reviewed FERC's orders approving restructuring agreements between Transco and its customers. The petitioners challenged Transco's passthrough of its above-market cost of SNG from Great Plains on the basis that "customers should pay rates based only upon the costs they cause the pipeline to incur." *Id.* at 873. We rejected that argument, however, concluding that the departure from cost-causation principles was justified because, "had the Great Plains plant succeeded in increasing the supply of natural gas, it would have contributed also to reducing the price of natural gas, to the benefit of all natural gas consumers." *Id.* at 874.

The PUCs argue that *Elizabethtown III* is inapposite because it did not consider the treatment of *Great Plains gas* in a restructuring proceeding in light of the overall purposes of Order No. 636. Although the PUCs are correct that *Elizabethtown III* does not address *Great Plains gas* in light of Order No. 636, we note that the case was both argued (February 23, 1993) and decided (December 17, 1993) after the issuance of Order No. 636 (April 16, 1992), Order No. 636-A (August 12, 1992), Order No. 636-B (November 27, 1992), and even Order No. 636-C (January 8, 1993). The *Elizabethtown III* court thus had ample opportunity to consider the consistency of the *Great Plains* volumetric surcharge with the overall policy objectives of the Order No. 636 regime. Petitioners point to no developments since the *Elizabethtown III* decision that effectively distinguish that case from the issue before us, and we are accordingly constrained by *Elizabethtown III*'s treatment of the Great Plains issue. We therefore reject petitioners' challenges to FERC's treatment of Great Plains gas.

Appendix A

E. *GSR Costs*

In this part of the opinion, we consider petitioners' challenges to the GSR costs that arose from the modification of producer-pipeline contracts. Order No. 636 both (1) required pipelines to unbundle their firm sales contracts into separate transportation and gas sales arrangements and (2) permitted customers to reduce or eliminate their obligations to buy gas from pipelines under the sales component. The pipelines, with fewer sales customers, were in turn forced by market pressures to buy their way out of many costly supply contracts with gas producers, thereby incurring some $1.7 billion in "gas supply realignment (GSR) costs." In Order No. 636, the Commission authorized pipelines to recover 100% of their prudently incurred GSR costs from their blanket-certificated transportation customers.[91]

Petitioners raise several objections to this recovery policy, all of which we conclude are ripe for review. First, they argue that FERC should have used its NGA § 5 authority to require gas producers to bear part of the GSR costs. We conclude that FERC reasonably declined to exercise the limited authority it possessed over producer-pipeline contracts. Second, petitioners contend that the Commission erred in its assignment of GSR costs to two classes of pipeline transportation customers. By and large, we conclude that the Commission's allocation of GSR costs among customers was an acceptable application of "cost

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91. In Order No. 636-B, ¶ 61,272, at 52,040-41, the Commission suggested that those pipelines that offered discounted transportation services might not be permitted 100% recovery, a statement that the pipelines challenged in this proceeding. The Commission has since withdrawn that suggestion, however, *Natural Gas Pipeline Co. of Am.*, 69 FERC ¶ 61,029, at 61,116-17 (1994), rendering the pipelines' claim moot.

spreading" and "value of service" principles. We do conclude, however, that the Commission has failed to explain adequately its decision in all instances to allocate 10% of GSR costs to the pipelines' interruptible transportation customers. Third, petitioners contend that the pipelines themselves should have been required to absorb some portion of their GSR costs. After carefully reviewing the issue, we conclude that the Commission did not engage in reasoned decisionmaking such that we can sustain its decision to exempt the pipelines altogether. We do not hold that the Commission was required to assign a particular portion of GSR costs to pipelines, however, but instead remand this question (along with the 10% interruptible transportation figure) for further consideration.

1. *Ripeness of petitioners' challenges to FERC's treatment of GSR transition costs*

"Settled principles of ripeness require that [a court] postpone review of administrative decisions where (1) delay would permit better review of the issues while (2) causing no significant hardship to the parties." *Northern Indiana Public Service Co. v. FERC*, 954 F.2d 736, 738 (D.C.Cir.1992) (*NIPSCO*). FERC argues that none of the petitioners' challenges to its allocation of GSR costs are ripe for review. It notes that, under Order No. 636, "a pipeline may file . . . to recover GSR costs only after it has restructured its system in full compliance with the rule" and argues that disputes over GSR cost recovery are therefore better left to individual restructuring proceedings. *See* Order No. 636, ¶ 30,939, at 30,460; Order No. 636-B, ¶ 61,272, at 62,042. Additionally, FERC noted in Order No. 636-B that the Order No. 636 series transition cost policies "are not incorporated in the regulations, but are policy statements." Order No. 636-B, ¶ 61,272, at 62,034-35. It further explained that it

would "review specific proposals for recovering transition costs with reference to the particular circumstances of each pipeline system and the degree of support those proposals enjoy from the affected parties." *Id.*; *see also* Order No. 636-A, ¶ 30,950, at 30,648-49 ("Guidelines and policies will be developed . . . in concrete cases" to address concerns about GSR cost recovery.). FERC thus compares this case to AGA I, 888 F.2d 136, which held unripe challenges to Order No. 500's equitable sharing policy in light of the strong norm against reviewing policy statements and other tentative agency positions where no hardship will result to the parties.

The problem with FERC's ripeness argument is that it fails to meet NIPSCO's two criteria for declaring a case unripe. The Commission claims that it intended in the Order No. 636 series to merely announce a general policy approach to GSR costs and leave analysis of specific GSR cost disputes to individual pipeline restructuring proceedings. "Where the language and context of [an agency] statement are inconclusive, we have turned to the agency's actual applications." *Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682 (D.C.Cir.1991). In this case, FERC's treatment of the GSR cost issue in subsequent proceedings is inconsistent with a general policy approach. For example, in restructuring proceedings for Texas Eastern Transmission Corporation, petitioners challenged FERC's allocation of GSR costs, but FERC determined that "[b]ecause the Commission has addressed all of the Industrial Groups' arguments in Order No. 636 et seq., the Industrial Groups' request for rehearing is denied." *Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,100, at 61,512 (1993). In Texas Eastern's NGA § 4 filing for the recovery of GSR costs, FERC again refused to consider these arguments. *See Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,254, at 63,245-46 (1993). In *Columbia Gas Transmission*

Corp., 64 FERC ¶ 61,365, at 63,588 (1993), FERC refused to consider certain GSR cost arguments because they were "essentially a request for rehearing of Order No. 636. There is no need to revisit these arguments again. We deny rehearing." In *ANR Pipeline Co.*, 64 FERC ¶ 61,140, at 62,083-84 (1993), FERC rejected arguments about GSR costs "for the same reasons stated in Order No. 636-B."

Unlike the situation in *Papago Tribal Utility Authority v. FERC*, 628 F.2d 235, 240 (D.C.Cir.1980), where we found that FERC might "resolve the claims of the parties and obviate any injury to them if we allow it to complete its proceedings," FERC has demonstrated that it does not plan to offer any significant justifications for its treatment of GSR costs as outlined in the Order No. 636 series other than those presented in the Order No. 636 series itself. We therefore hold that FERC's treatment of GSR costs does not constitute an unreviewable general "policy statement" but rather a final determination ripe for judicial review. Because FERC continually relies on the Order No. 636 series' treatment of GSR costs, it is not reasonable to conclude that a delay in review would permit better review of the issue.

The second part of the NIPSCO test asks whether delay in review would cause significant hardship to the parties. Put another way, the petitioners must show "a direct and immediate effect on their primary conduct." *Tenneco Gas v. FERC*, 969 F.2d 1187, 1211 (D.C.Cir.1992). FERC admits that Order No. 636 GSR costs as of February 7, 1996, totaled almost $1.7 billion without interest, hardly an insignificant amount. In any case, it is unlikely that FERC would have gone to such lengths to assure that pipelines recover 100% of GSR costs if those costs were unlikely to have an immediate effect on the conduct of the parties having to pay them. Furthermore, to the extent that pipelines

and gas producers continue to renegotiate contracts, such negotiations will undoubtedly be affected by FERC's treatment of GSR costs in the Order No. 636 series (and in the individual restructuring proceedings). We accordingly conclude that FERC's treatment of GSR costs causes "a direct and immediate effect" on the petitioners' primary conduct, and that the petitioners' claims are ripe for review.

2. *Gas producers' exemption from GSR costs*

In the Order No. 636 series proceedings, petitioners presented several alternative solutions to the transition cost problems, some of which would have required that FERC abrogate existing contractual obligations between pipelines and gas producers. These alternative solutions would have forced gas producers to bear part of the transition costs. FERC declined to adopt these proposals on the grounds that, among other things, it lacked § 5 authority to abrogate producer-pipeline contracts. Order No. 636-A, ¶ 30,950, at 30,643. The Commission is correct that it lacks such authority. We have already said as much in *AGA II*, 912 F.2d at 1505, where we concluded that Congress unambiguously restricted FERC's § 5 powers to jurisdictional contracts. And FERC's jurisdiction over wellhead contracts began to decline as soon as Congress eliminated such jurisdiction over new wellhead contracts. *See NGPA* § 601(a)(1)(A), (B), 15 U.S.C. § 3431(a)(1) (A), (B); *Pennzoil Co. v. FERC*, 645 F.2d 360, 380 (5th Cir.1981). The PUCs' claims that FERC's authority to regulate pipeline rates for the benefit of consumers gives it implicit authority over nonjurisdictional contracts crumble against the wall of the *AGA II* holding.

The PUCs also argue that, even if *AGA II* applies, FERC still retained jurisdiction over some "old" gas contracts when it

issued Order No. 636 and that it should have used its § 5 authority to reform those contracts. (In AGA II we recognized that FERC still had jurisdiction over some wellhead contracts, noting that "[t]he proportion of wellhead sales that is subject to FERC jurisdiction steadily declines . . . as old gas is exhausted." *AGA II*, 912 F.2d at 1505.) But exercising such jurisdiction would have conflicted with Congress' clear intent that FERC get out of the business of regulating wellhead gas prices, making such an approach a questionable vehicle for addressing the petitioners' concerns. Furthermore, as FERC noted in Order No. 636-A, its jurisdiction "over most producer/pipeline supply contracts has already been removed under the NGPA. As of January 1, 1993, there will be no remaining vestiges of such jurisdiction by virtue of the Decontrol Act." Order No. 636- A, ¶ 30,950, at 30,643 n.460. In light of these concerns, it would be unreasonable to conclude that FERC should have reformed any producer-pipeline contracts to force producers to bear part of the GSR costs. We accordingly decline to accept the petitioners' invitation to remand this issue to the Commission.

3. *Allocation of GSR costs among customer classes*

Order No. 636 authorizes pipelines to recover their GSR costs from all of their blanket-certificated transportation customers. Petitioners contend that the Commission erred in allocating costs to two specific classes of customers: customers that were not directly responsible for GSR costs under Order No. 636 (*i.e.*, those that did not reduce their pipeline gas purchases in response to mandatory unbundling); and interruptible transportation customers. FERC defends its allocation of GSR costs based on the principles of "cost spreading" and "value of service." It is there that we begin.

Appendix A

a. *"Cost spreading" and "value of service"*

Order No. 500, the immediate successor to Order No. 436, authorized pipelines to recover take-or-pay costs from both their customers that were blanket certificated under the Commission's open-access regime and customers that were individually certificated under NGA § 7(c). The § 7(c) shippers objected that they were merely transportation customers of pipelines, and were therefore not in any way responsible for the fact that the pipelines, in preparing to accommodate their anticipated sales obligations, had incurred take-or-pay liabilities. According to the § 7(c) shippers, the Commission's allocation of take-or-pay costs therefore violated accepted principles of "cost causation," under which "[p]roperly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer," *Alabama Electric Coop. v. FERC*, 684 F.2d 20, 27 (D.C.Cir.1982) (citation and internal quotation marks omitted).

The Commission conceded that its take-or-pay allocation could not be sustained under a narrow view of cost causation. It argued, however, that "circumstances surrounding the take-or-pay crisis and the transformation of the pipeline industry necessitate and justify the crafting of new ratemaking principles." *K N Energy v. FERC*, 968 F.2d 1295, 1301 (D.C.Cir.1992). Specifically, the Commission defended its policy on grounds of "cost spreading" and "value of service":

> Under this first notion, allocating take-or-pay costs to transportation customers who admittedly may not have directly caused them is acceptable because, in the

> Commission's judgment, the extraordinary nature of this problem requires the aid of the entire industry to solve it; there are no other alternatives that would allow a transition to a market-based pipeline industry to be effectuated. Closely related to this rationale is FERC's second: namely that all segments of the industry — including those who may not have caused take-or-pay problems — will nonetheless ultimately benefit from their resolution and the concomitant move toward an open access regime; consequently, all segments can rightly be assessed a portion of take-or-pay costs.

Id.

In *K N Energy*, we sustained the Commission's invocation of "cost spreading" and "value of service," *id.* at 1302, though we made clear that our approval of those principles was limited, *see id.* ("A more searching inquiry may well prove necessary . . . if the Commission should attempt to adopt these ratemaking rationales outside the take-or-pay context."). We did not, however, approve of the Commission's conclusion that application of "cost spreading" and "value of service" justified billing take-or-pay costs to § 7(c) customers. While the Commission contended that § 7(c) customers benefitted from Order Nos. 436 and 500 through lower transportation rates, the data before the court suggested that those rates had in fact increased. *Id.* Moreover, the Commission's Orders allocated costs to pipelines' remaining sales customers inconsistently. *Id.* at 1303. We therefore remanded for further consideration of the

manner in which take-or-pay liabilities should be applied to § 7(c) customers.[92]

In this case, the Commission contends that its assignment of GSR costs to all blanket-certificated shippers was an appropriate application of "cost spreading" and "value of service" principles.

b. *Petitioners' challenges*

1.) *Limitation to bundled sales customers*

The Industrial End-Users object to FERC's decision to allow recovery of transition costs from all blanket-certificated transportation customers, including those that were not pipeline sales customers at the time of the implementation of Order No. 636. The ground for their objection is straightforward: GSR costs arose from the contracts between the pipelines and those firm sales customers that they retained after Order No. 436, not from contracts with customers that had previously converted under Order No. 436. Specifically, Order No. 636 required firm sales customers to convert their sales entitlements into firm transportation entitlements. Some of those customers also exercised their option to reduce their pipeline gas purchases, leaving the pipelines with excess sales capacity, purchase obligations, and related costs:

> Indeed, nearly 65 percent of pipeline capacity was committed to sales customers prior to Order 636 even though pipelines' sales accounted for less than 20% of deliveries by

92. On remand, the Commission concluded that the application of take-or-pay costs to § 7(c) customers was not justified. *Williston Basin.*

> 1991. Transportation customers who had earlier converted under Order 436 and 500 from sales service to transportation service, or who had never been pipeline sales customers, had already negotiated their gas supply arrangements and had previously paid the cost of restructuring prior to Order 636. Significantly, nothing in Order 636 permits these transportation customers to reform their supply or transportation arrangements (or to pass on to others the associated costs).

Industrial End-Users' Br. at 18 (emphasis in original). The contracts of non-sales customers therefore did not directly give rise to Order No. 636 GSR costs.[93] The Industrial End-Users further note that even if customers that had previously converted to firm transportation service benefit from Order No. 636, the Commission made no attempt to correlate the degree of that benefit with its cost allocation decisions.[94]

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93. The same is true of § 7(c) individually certificated shippers, which FERC exempted from paying GSR costs under Order No. 636. The Industrial End-Users maintain that exempting § 7(c) shippers but including all Part 284 shippers is arbitrary. As is discussed in Part III.C.1, *supra*, however, FERC excluded § 7(c) shippers both from the capacity release program and from paying transition costs in order to equitably spread both the costs and benefits of Order No. 636.

94. The Small Distributors and Municipalities briefly make the separate argument that the Commission's allocation of GSR costs constitutes unlawful "retroactive ratemaking." They contend that "many small customers had converted to transportation prior to July 31, 1991 [the date of issuance for the Order No. 636 Notice of Proposed Rulemaking] and were therefore not on notice that they would be held responsible for such pipeline gas supply

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FERC's approach in Order No. 636, however, is valid under the value-of-service and cost-spreading rationales approved by this court in the *K N Energy* decision. Even those customers not directly responsible for GSR costs benefit from the availability of lower priced transportation in the unbundled marketplace. Moreover, the Commission's options in spreading out costs to pre-Order No. 636 firm sales customers are substantially limited by the filed rate doctrine and the bar to retroactive ratemaking; FERC simply cannot reach backwards through time in a truly equitable manner. While the Industrial End- Users correctly note that to date we have approved the Commission's departure from traditional cost-causation principles in only limited circumstances, those circumstances are squarely presented in this case. GSR costs under Order No. 636 are the functional equivalent of take-or-pay costs under Order No. 436, and "the Commission has not betrayed its obligations to the NGA or precedent by employing these ratemaking principles in its attempt to bring closure to the take-or-pay drama," *K N Energy*, 968 F.2d at 1302.

2.) *Interruptible transportation customers*

The Industrial End-Users challenge the Commission's decision to allocate 10% of a pipeline's GSR costs to interruptible transportation customers.[95] They contend that

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costs when taking transportation service prior to that date." Those customers, however, were on notice as of July 31, 1991 that if they continued to receive open-access transportation services, they would be responsible for paying GSR costs that arose after that date. *See* Notice of Proposed Rulemaking, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 32,480, at 32,560 (1991).

95. While the Commission suggests that in the restructuring proceedings

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unbundling confers no real benefit on that class of customers, who therefore should not be responsible for paying GSR costs. They further contend that interruptible transportation customers in fact may receive inferior service after Order No. 636 because the higher volume of firm transportation expected to result under the Commission's capacity release program may displace interruptible transportation services. Moreover, given that less gas is transported by interruptible than firm transportation, the GSR surcharges applied to interruptible transportation in some cases may exceed those charges applied to firm transportation.

The Small Distributors and Municipalities concur that FERC should have better spread the costs of restructuring throughout the industry, but take the contrary position that additional costs should have been allocated to interruptible transportation. Invoking "benefit of service" principles,[96] the brunt of their claim is a relatively complex economic analysis of why interruptible transportation customers stand to gain a great deal under Order No. 636. In sum, their theory is that the customers who receive the most benefit under Order No. 636 are those with elastic demands, *i.e.*, those most likely to use interruptible transportation.

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it may consider the manner in which the 10% is collected, it apparently does not consider the 10% figure itself open to negotiation. In three cases, the Commission has required the allocation of 10% of GSR costs to interruptible transportation cases based expressly on the ruling in Order No. 636-A. *See Texas Gas Transmission Corp.*, 68 F.E.R.C. ¶ 61,118, at 61,594 (1994); *Florida Gas Transmission Co.*, 63 F.E.R.C. ¶ 61,160, at 62,079, 1993 WL 308439 (1993); *Southern Natural Gas Co.*, 62 F.E.R.C. ¶ 61,136, at 61,946 (1993).

96. The Small Distributors and Municipalities also contend that under the same principles GSR costs should be allocated to gas producers. This point is discussed above, *see supra* Part V.E.2.

Our concerns here mirror those in our review of the application of take-or-pay costs to § 7(c) customers in *K N Energy*. The fact that interruptible transportation customers are part of the "natural gas industry" is not, standing alone, sufficient to assign them GSR costs; even the "cost spreading" and "value of service" principles that we have approved allow for the imposition of costs only upon those entities that either bear some responsibility for the costs or derive some benefit from the solution imposed. *See K N Energy*, 968 F.2d at 1302-04. We are quite sensitive to the Commission's expert conclusion that interruptible transportation customers do derive benefits from unbundling under Order No. 636; an active market for firm transportation would seem likely to drive down the cost of less desirable interruptible transportation, and while the additional use of firm transportation under Order No. 636 may crowd out some interruptible transportation, that results at least in part from customers converting from interruptible to firm service. Moreover, unlike our review of Order No. 500, we are not presented in this case with evidence that the Commission's prediction of reduced costs was wrong as a factual matter. Further still, interruptible transportation customers do clearly benefit from Order No. 636 through access to low cost transportation that is available through the Commission's capacity release mechanism.

More troubling, however, is the Commission's apparently stringent adherence to the 10% figure in all instances. FERC elected to allocate GSR costs to interruptible transportation (IT) in response to claims by some pipelines that they would not be able to recover all of their transition costs from firm customers alone. It completely failed, however, to explain why it chose 10% rather than 5% or 15%, and why that 10% figure should be applied to every pipeline; the Orders and FERC's brief simply

do not attempt to defend that figure whatsoever. For example, we are presented with absolutely no explanation of why IT should contribute 10% of GSR costs even on those pipelines on which IT constitutes less than 10% of throughput. And, while the Commission correctly points out that courts have recognized the inherent ambiguities in ratemaking, that does not immunize an agency from engaging in reasoned decisionmaking that is susceptible of appellate review. As we explained in reviewing Order No. 500:

> While we owe the Commission substantial deference in matters predictive and economic, we cannot ignore the Commission's unwillingness to address an important challenge to its stated benefit rationale for charging transportation customers. It most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it — that it conduct a process of reasoned decisionmaking. The deference we owe FERC's expert judgment does not strip us of that responsibility. Indeed, . . . we will uphold an agency's decision "if, but only if, we can discern a reasoned path from the facts and considerations before the [agency] to the decision it reached."

Id. at 1303 (citations omitted) (second emphasis added).

In this instance, we cannot discern the Commission's path from its view that interruptible transportation customers should bear some of the burden for GSR costs to the conclusion that

the share should be 10%. *Cf.* WALT WHITMAN, LEAVES OF GRASS, Darest Thou Now O Soul ("Darest thou now O soul, Walk out with me toward the unknown region, Where neither ground is for the feet nor any path to follow?"). And, while we are sympathetic to the Commission's view that "[t]he task of determining fair allocations of transition costs is ultimately thankless, even though [it] bring[s] all [its] experience and best judgment to bear on it," Order No. 636-B, ¶ 61,272, at 62,034, the law requires more than simple guesswork.[97] We therefore remand the issue to the Commission for further consideration.

4. *Pipelines' exemption from GSR costs*

To this point, petitioners' objections to the distribution of GSR costs have involved the allocation of those costs among groups of pipeline transportation customers. As a separate matter, petitioners forcefully contend that the Commission erred in not requiring the pipelines themselves to absorb any GSR costs. They note the remarkable similarities between Order No. 636 GSR costs and Order No. 436 take-or-pay costs, and contend that the pipelines should absorb GSR costs just as they do take-or-pay costs. While we do not conclude that the Commission necessarily was required to assign the pipelines responsibility for some portion of their GSR costs, we do agree with petitioners that the Commission's stated reasons for exempting the pipelines do not rise to the level of "reasoned decisionmaking." We therefore remand the issue to the Commission for further consideration.

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97. In point of fact, there may be unique circumstances in which it is simply impossible to attribute costs with anything resembling mathematical accuracy. In such instances, however, the Commission still must take the time to explain why that is the case.

Initially, we agree with petitioners that the Commission's stated rationale for allocating take-or-pay costs to pipelines substantially applies in the context of GSR costs as well. As we explained above, *see supra* Part V.A, take-or-pay and GSR costs both arise from the same provisions in producer-pipeline contracts and result from pipelines' former firm sales customers reducing their gas purchases. We therefore find it instructive that in the take-or-pay context, the Commission itself concluded that pipelines should bear some of the burden, reasoning that

> allowing a pipeline to recover 100 percent of its settlement costs through a fixed charge would be inconsistent with the Commission's holding in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problem.

Order No. 500-H, ¶ 30,867, at 31,575. In Order No. 636 as well, the Commission acknowledged that GSR costs had arisen at least in part due to the conduct of the pipelines, characterizing bundled sales arrangements, which arose in substantial part from pipelines' market power, as an unreasonable and unlawful restraint of trade. Order No. 636, ¶ 30,939, at 30,405. Moreover, according to the Commission, the pipelines benefit from Order No. 636, in that they "will presumably receive more favorable prices or other valuable consideration resulting from contract reformation." Order No. 636-A, ¶ 30,950, at 30,643; *cf. id.* at 30,642 ("[Petitioners] generally allege that since Order No. 636 will benefit all segments of the gas industry, all segments should bear the costs. The Commission believes that the benefits of Order No. 636 indeed will be widespread.").

The Commission nevertheless puts forward a wide variety of arguments for exempting pipelines from paying GSR costs, which we will address on the merits seriatim. We begin, however, by noting that, as a general matter, the Commission's arguments seem directed toward proving the wrong point. FERC allocated Order No. 636 GSR costs to customers based on the principles of "cost spreading" and "value of service" discussed above, *see supra* Part V.E.3.a. When it exempted the pipelines from those costs, however, the Commission reverted to traditional concepts of "cost causation," or to use its characterization, "returned to first principles holding that a utility is entitled to the opportunity to recover all of its prudently incurred costs in providing public service."[98] It is important to emphasize that these are competing models for allocating the industry's costs of service. "Cost causation" correlates costs with those customers for whom a service is rendered or a cost is incurred. For example, as we noted above, *see supra* Part V.E.3.b.1, the Industrial End-Users argue that under a cost causation model, the only customers who should be required to pay GSR costs are those that reduced their pipeline gas purchases in response to Order No. 636. "Cost spreading" and "value of service," in contrast, take a much wider view, assigning the costs of service to those classes of industry participants that either are at fault for the take-or-pay dilemma or benefit from its resolution. Applying these latter principles, we sustained the Commission's determination that GSR costs should be paid by all blanket-certificated transportation customers, even those that did not directly cause the pipelines

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98. Of course, there may be a world of difference between what the Commission views as pipelines' legal entitlement to recover GSR costs by charging their remaining sales customers higher prices and the pipelines' economic ability to do so in the marketplace. *See supra* at 115 (discussing possibility of pipelines' "death spiral" of higher prices and smaller customer base).

to incur liabilities under their supply contracts. *See supra* Part V.E.3.b.1.

If the Commission intends to assign GSR costs according to these "cost spreading" and "value of service" principles, it must do so consistently or explain the rationale for proceeding in another manner.[99] We approved the invocation of those principles in *K N Energy* because FERC had concluded that the take-or-pay crisis could be resolved only by spreading costs throughout the "entire industry," 968 F.2d at 1301 (emphasis added), and because we recognized that "all segments of the industry . . . will benefit," *id.* (emphasis added), from restructuring. *Cf.* Order No. 636-A, ¶ 30,950, at 30,650 ("[I]n the Commission's judgment, [Order No. 636] continues the general goal of spreading the costs of industry restructuring.").[100] The Commission therefore cannot, without explanation, burden blanket-certificated transportation customers on the ground that they will benefit from Order No. 636, and then ignore that same factor as it relates to the pipelines. For example, the fact that both pipelines and customers will benefit from expanded open-access transportation is one argument in favor of applying GSR costs to both. On the other hand, it is not particularly relevant

99. For example, the Commission may conclude that responsibility for GSR costs would cause such harm to a particular segment of the industry as to raise substantial concerns about its economic health. In this case, FERC contended that it exempted pipelines from paying GSR costs because of the pipelines' precarious financial position. The Commission never articulated that rationale in the proceedings below, however, and we therefore do not consider it. *See Burlington Truck Lines v. United States*, 371 U.S. 156, 168-69, 83 S.Ct. 239, 245-46, 9 L.Ed.2d 207 (1962). The issue remains open for further consideration on remand.

100. This applies, of course, only to those entities over which the Commission may lawfully exercise jurisdiction. *See supra* Part III.B.

that GSR costs will total only approximately $1.7 billion, while take-or-pay costs were $10 billion, for that proves nothing about the relative responsibility of various segments of the industry for those costs. On the same footing is the Commission's recognition that pipelines have already paid $3.6 billion in take-or-pay costs; petitioners are quite right when they note that consumers have in the end paid nearly twice that amount. The relevant question is instead whether the $3.6 billion dollar figure should be even larger — recognizing that the figure for consumers is sure to grow — because the pipelines are in part responsible for GSR costs and will benefit from Order No. 636.

This is not to say, however, that it is impossible, or even improbable, that the Commission on remand can establish a convincing rationale for exempting the pipelines. For example, arguably, the pipelines' contribution to the costs of theindustry's transition has already been so disproportionately large vis-a-vis consumers that they are entitled to be excused from further responsibility. It also may be that unbundling under Order No. 636 benefits consumers so much more than it does the pipelines that the pipelines should bear few or no GSR costs. Such issues, however, require a fuller airing in the administrative proceedings on remand than is evident from the record developed in the initial go-round.

Two final arguments raised by the Commission merit separate attention. First, it notes that unbundling under Order No. 436 was voluntary while under Order No. 636 it is mandatory. It is unclear in the Order No. 636 series, however, how the "voluntariness" of the reduction in pipeline gas purchases correlates with the pipelines' responsibility for the resulting costs. The fact that certain pipelines made an economic choice to convert to open-access transportation and thereby

almost certainly incur take-or-pay costs under Order No. 436 does not make other pipelines less responsible for the same type of costs when the Commission ultimately decided that it had to force the final stages of industry restructuring. Moreover, we rejected that very distinction when we vacated Order No. 436:

> FERC also alludes to the "voluntary" character of pipeline provision of Order No. 436 transportation. There are two flaws in this. First, refusal of the option may spell bankruptcy: inability to provide blanket-certificate transportation for fuel-switchable users may in current market circumstances cause critical load loss . . . .
>
> Second, the argument obscures distinctions between pipelines in the aggregate and alone. To be sure, Order No. 436 gives pipelines an option, blanket-certificate transportation, which . . . is not available outside of Order No. 436. But as soon as a single pipeline finds it attractive enough to accept, each competing pipeline will come under competitive pressure to match the first's flexibility.

AGD I, 824 F.2d at 1024.

The Commission also notes that under Order No. 500, but not Order No. 636, those pipelines that paid take-or-pay costs received a heightened presumption that those liabilities were prudently incurred.[101] As with "voluntariness," however, the

101. Order No. 636 subjects GSR charges to the same form of prudence (Cont'd)

Appendix A

Order No. 636 series does not explain how the presumption of prudence correlates with FERC's cost-spreading and value-of-service rationales. The Orders' differing treatment of prudence stems from the fact that Order No. 500 and its successors allowed pipelines to recover some, but not all, of their take-or-pay liabilities through a fixed charge on transportation if and only if they absorbed some of those costs themselves. The presumption of prudence created an incentive for the pipelines to engage in cost absorption in that it reduced expenses they might later incur in litigating the appropriateness of their take-or-pay liabilities. Order No. 636 needs no such incentive because pipelines can directly bill transportation customers for 100% of GSR costs, an option that was never available under Order No. 500. And,

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(Cont'd)

review generally applied to pipeline billings. Thus, customers have the burden of proving any claim they might press that particular GSR charges were not prudently incurred. Order No. 636-B, ¶ 61,272, at 62,039. Petitioners challenge the Commission's conclusion that "the possibility of having to defend the incurrence of [GSR] costs, and suffer disallowance of recovery, should provide sufficient incentive for pipeline diligence in minimizing these costs," Order No. 636, ¶ 30,939, at 30,461. Prudence review, however, is a well-settled practice, and petitioners have offered no particular reason for disallowing its use in this context. In point of fact, petitioners' complaint in large part seems to be that the Commission's application of its prudence standards is too lax, not that the use of prudence review is per se unlawful. *See id.* at 26 (citing *Columbia Gas Trans. Corp.*, 26 F.E.R.C. ¶ 61,034, on reh'g, 26 F.E.R.C. ¶ 61,334 (1984); *Texas Gas Trans. Corp.*, 48 F.E.R.C. ¶ 61,266 (1986), as examples of inadequate prudence review). We do not foreclose such claims from being raised in any petition for review of a ruling by the Commission that a pipeline's GSR costs were prudently incurred. The same holds true for petitioners' claim that the Commission will fail to distinguish correctly between Order No. 636 GSR costs and charges that pipelines should properly recover as Order No. 436 take-or-pay costs. We may review the question when properly presented with a ruling by the Commission on particular GSR costs.

of course, were the Commission on remand to assign some proportion of GSR costs to pipelines, it could apply the same presumption of prudence that it used in the take-or-pay context.

In sum, we cannot conclude from the record now before us that the Commission's decision to exempt pipelines completely from paying GSR costs was the product of reasoned decisionmaking. Order No. 636 is based on principles of cost spreading and value of service that are, in turn, premised on the notion that all aspects of the natural gas industry must contribute to the transition to an unbundled marketplace. In addressing pipelines' liability for GSR costs, however, the Commission at the very least undervalued those considerations. We leave it to the Commission on remand to consider whether the pipelines should nonetheless continue to be exempted from such costs in light of the factors we have identified.

F. *Conclusion*

With respect to stranded costs, we hold that FERC's interpretation of the used and useful doctrine is supported by substantial evidence. We reject petitioners' argument that FERC inadequately addressed the LDC bypass issue, and we also reject petitioners' challenges to the volumetric surcharge for above-market Great Plains gas.

Turning to GSR costs, we first conclude that petitioners' challenges are ripe for review. Next, we hold that FERC did not err by failing to exercise its NGA § 5 authority so as to force gas producers to bear part of the transition costs. Furthermore, we sustain the Commission's application of GSR costs to the full range of blanket-certificated transportation customers. We remand the case to the Commission, however, for further

consideration of the appropriate share of those costs to be paid by interruptible transportation customers and the gas pipelines.

VI. Conclusion

In its broad contours and in most of its specifics, we uphold Order No. 636. However, we remand certain aspects of Order No. 636, which we now recount, to the Commission for further explanation. With regard to no-notice transportation service, we remand for the Commission to explain why it restricted entitlement to receive no-notice service to those customers who received bundled firm-sales service on May 18, 1992. We remand the right-of-first-refusal mechanism for the Commission to explain why it adopted a twenty-year term-matching cap. Two aspects of the SFV mitigation measures require further explanation: first, the decision to require initial mitigation measures, such as seasonal contract adjustments, on the basis of the effect of switching to SFV on individual customers, whereas the four-year phase-in mitigation measure is determined by the effect on customer classes; and second, the decision that former customers of downstream pipelines are ineligible for small-customer rates. Finally, with regard to the recovery of GSR costs, we remand for an explanation of why, in light of the equitable- sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636, pipelines can pass through all their GSR costs to customers, and also for an explanation of why the Commission decided, in allocating costs among customers, that interruptible-transportation customers should bear 10% of GSR costs.

Until the Commission takes final action on remand, however, we leave these measures in place as currently formulated. *See A.L. Pharma, Inc. v. Shalala*, 62 F.3d 1484, 1492

(D.C.Cir.1995); *Checkosky v. SEC*, 23 F.3d 452, 462-65 (D.C.Cir.1994) (opinion of Silberman, J.); *cf. AGA I*, 888 F.2d at 153 (stating that the Commission must promptly provide a reasoned explanation).

It is so ordered.

APPENDIX B — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636", F.E.R.C. STATS. & REGS. (CCH) ¶ 30,939 (1992)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-000

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-065

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Before Commissioners: Martin L. Allday, Chairman;
Charles A. Trabandt,
Elizabeth Anne Moler,
Jerry J. Langdon and Branko Terzic.

ORDER NO. 636

FINAL RULE

(Issued April 8, 1992)

Appendix B

I. INTRODUCTION

By adopting the proposed rule with modifications, this rule requires significant alterations in the structure of interstate natural gas pipeline services in light of the changes in the natural gas industry brought about by the Natural Gas Policy Act of 1978 (NGPA),[1] the Commission's open access transportation program,[2] and the Natural Gas Wellhead Decontrol Act of 1989 (Decontrol Act).[3] The Commission believes that this rule, when fully implemented, will finalize the structural changes in the Commission's regulation of the natural gas industry. This rule will therefore reflect and finally complete the evolution to competition in the natural gas industry initiated by those changes[4] so that all natural gas suppliers, including the pipeline

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1. 15 U.S.C. 3301-3432 (1988).

2. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,665 (1985), *vacated and remanded*, Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988), *readopted on an interim basis*, Order No. 500, 52 FR 30334 (Aug. 14, 1987), FERC Stats. & Regs. [Regulations Preambles, 1986-1990] ¶ 30,761 (1987), *remanded*, American Gas Association v. FERC, 888 F.2d 136 (D.C. Cir. 1989), *readopted*, Order No. 500-H, 54 FR 52344 (Dec. 21, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 (1989), *reh'g granted in part and denied in part*, Order No. 500-I, 55 FR 6605 (Feb. 26, 1990), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,880 (1990), *aff'd in part and remanded in part*, American Gas Association v. FERC, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991).

3. Pub L. No. 101-60, 103 Stat. 157 (1989).

4. Those changes are discussed in detail, *infra*.

as merchant, will compete for gas purchasers on an equal footing. As discussed below, this promotion of competition among gas suppliers will benefit all gas consumers and the nation by "ensur[ing] an adequate and reliable supply of [clean and abundant] natural gas at the lowest reasonable price."[5]

II. PUBLIC REPORTING REQUIREMENTS

The Commission estimates the public reporting burden as a result of this rule to be an average of 4,810 hours per response for FERC-545, 2.7 hours for FERC-549 and 9.94 hours for FERC-592. The annual reporting burden associated with this rule is estimated to be 428,090 hours for FERC-545, 410 hours for FERC-549, and 885.2 hours for FERC-592 for a total of 429,385.2 hours. The estimate includes time for reviewing the requirements adopted by this rule, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information and filing this information with the Commission. Most of the burden hours (428,090 hours under FERC-545) are related to a one-time implementation tariff filing requirement. Interested persons may send comments regarding these burden estimates or other aspects of these collections of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, DC 20426 [Attention: Michael Miller, (202) 208-1415]; and to the Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

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5. S. Rep. No. 39, 101st Cong., 1st Sess., at p. 1 (1989) and H.R. Rep. No. 29, 101st Cong., 1st Sess., at p. 2 (1989).

III. THE COMMISSION'S GOALS IN ADOPTING THIS RULE

The Commission's responsibility under the Natural Gas Act (NGA)[6] is to protect the consumers of natural gas from the exercise of monopoly power by pipelines[7] in order to ensure consumers "access to an adequate supply of gas at a reasonable price."[8] This mission must be undertaken by balancing the interests of the investors in the pipeline, to be compensated for the risks they have assumed, and the interests of consumers,[9] and in the light of current economic, regulatory, and market realities. Hence, the Commission must fulfill its NGA mandate in the context of the decontrolled gas commodity market, the competition among gas merchants (including pipelines) for gas sales to local distribution companies (LDCs) and end users, such as industrials and gas-fired electric generators, and continued pipeline market power over transportation. In addition, the Commission's goal here is informed by Congress' urging, when it enacted the Decontrol Act, that the Commission "improve [the]

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6. 15 U.S.C. 717-717w (1988).

7. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.").

8. Tejas Power Corp. v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

9. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). ("The rate-making process under the [NGA] . . . involves a balancing of the investor and consumer interests.").

competitive structure [of the natural gas industry] in order to maximize the benefits of [wellhead] decontrol."[10]

At the same time, the Commission recognizes that the natural gas industry has undergone significant changes in the past ten years. Historically, pipelines have served as gas merchants — buying gas at the wellhead and selling it at the city gate to LDCs. This bundled sales service was reliable and suited the regulatory and commercial situation then prevailing in the gas industry. Indeed, until recently, there was little, if any, competition between gas suppliers in the natural gas industry.

The Commission has recognized the movement to competition set in motion by the NGPA in 1978. From the special marketing programs in 1984, to the elimination of pipeline minimum bills, to Order Nos. 436 and 500, the Commission has sought to promote and expand access to the wellhead market. Now, the complete deregulation of the wellhead market is on the horizon. The Commission must, therefore, take further steps to ensure that the public can realize the full benefits of the competition at the wellhead.

Since the issuance of Order No. 436, the Commission's efforts to adopt a more competitive gas market have been hindered. Non-pipeline sellers have correctly argued that the transportation of their gas supplies is not comparable to the transportation embedded in a pipeline's sales service, particularly during peak periods. This hinders their ability to sell gas on a long-term basis. On the other hand, pipelines have argued that existing transportation service cannot be improved since they must retain capacity to meet LDCs' existing

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10. H.R. Rep. No. 29, *supra*, at p. 6.

certificated sales levels and fulfill their NGA section 7(c) service obligations. At the same time LDCs have argued that they cannot convert existing certificated firm sales service to transportation because that transportation may not be as reliable as existing pipeline bundled sales service during peak periods. In addition, LDCs have been concerned that transportation capacity will be abandoned at the end of the contract term, should they convert from firm sales to firm transportation.

This rule addresses all of those issues. First, the Commission is taking steps to equalize the transportation of gas sold by pipelines and nonpipeline sellers. Second, the Commission is providing a means to recover all of the costs of restructuring existing non-market sensitive gas supply contracts. Finally, the Commission is providing for a "no-notice" transportation service in response to those who have expressed a particular concern about reliability during peak periods. In addition, the Commission is responding to concerns about pregranted abandonment for transportation services at the end of the contract term.

The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system — a natural monopoly — does not give a competitive advantage to pipelines over other sellers in the sale of natural gas. This will ensure that the benefits of decontrol redound to the consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act.[11]

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11. "Repeal of the remaining wellhead controls will promote the (Cont'd)

Appendix B

The Commission's primary aim in adopting the instant regulations is to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service. The Commission will do this by regulating pipelines as merchants and as open access transporters in a manner that accomplishes two fundamental goals. The first goal is to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible. As the House Committee Report to the Decontrol Act stated: "All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies."[12]

The Commission's second fundamental goal is to accomplish the first goal in a way that continues to ensure consumers "access to an adequate supply of gas at a reasonable price."[13] The Commission will act in a way that harmonizes both goals and thereby promotes competition and protects gas consumers. The Commission's intent is to further "facilitat[e] the unimpeded operation of market forces to stimulate the production of natural gas . . . [and thereby] contribute to reducing our Nation's dependence upon imported oil, help to ensure the

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(Cont'd)

unimpeded transmission of market signals from burnertip to wellhead and thereby help to ensure adequate supplies of reasonably priced natural gas in the future." S. Rep. No. 39, *supra*, at p. 2.

12. H.R. Rep. No. 29, *supra*, at p. 6.

13. Tejas, *supra*, at 1003; H.R. Rep. No. 29, *supra*, at p. 2.

availability of clean-burning natural gas for purposes of addressing environmental problems and the need for electric generating capacity[.]"[14]

The Commission believes that to accomplish those objectives it is vital to give all gas purchasers (LDCs and end users, such as industrials and gas-fired electric generators) the ability to make market-driven choices about the price of gas as a commodity and about the cost of delivering the gas. Simply put, efficiency in the now national gas market can be realized only when the purchasers of a commodity know, in a timely manner, the prices of the distinct elements associated with the full range of services needed to purchase and then deliver gas from the wellhead to the burnertip. Only then will gas purchasers be able to purchase, based upon their needs, the exact services they want with full recognition of the prices that they would have to pay. And only then will the Commission be assured that all gas is transported to the market place on fair terms. What best serves the interests of gas purchasers — the ability to make informed choices — is also important for gas sellers. Nonpipeline sellers also need to know the prices of the distinct elements of pipeline services in order to price their product and to decide the exact pipeline services needed to bring their gas to market. This rule provides both gas purchasers and gas sellers with the ability to make the necessary informed choices.

The Commission is adopting the major elements of the proposed rule, as modified below. In brief, this rule requires pipelines to unbundle (*i.e.*, separate) their sales services from their transportation services at an upstream point near the production area and to provide all transportation services on a

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14. S. Rep. No. 39, *supra*, at p. 2.

basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier. This rule issues blanket sales certificates to pipelines so that they can offer unbundled firm and interruptible sales services at market-based rates. In addition, pipelines will be required to provide a variety of transportation services to their shippers. This includes a new unbundled "no-notice", firm transportation service, firm transportation service that is unbundled and improved in quality, unbundled storage services, and interruptible transportation services, among others. As stated above, this will permit gas purchasers and gas sellers to choose the exact transportation service that they want, including a combination of services that will ensure that the pipelines can deliver an adequate supply of gas to the city gate from various sources when that supply is needed.

This rule also amends Section 284.221(d) of the Commission's Regulations[15] in further response to the remand of the United States Court of Appeals for the District of Columbia Circuit in *American Gas Association v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (*AGA II*).[16] The amendment to Section 284.221(d) would allow pregranted abandonment for interruptible and short-term (one year or less) firm transportation, and for long term (over one year) firm transportation under certain conditions. In addition, this rule adopts the straight fixed variable method for rate design,

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15. 18 CFR 284.221(d).

16. As discussed below, on February 13, 1991, the Commission's initial response to the AGA II remand was to issue an order staying in part Section 284.221(d). Natural Gas Pipelines After Partial Wellhead Decontrol, 56 FR 6962 (Feb. 21, 1991); III FERC Stats. & Regs. ¶ 30,915 (Feb. 13, 1991) (Order No. 500-J).

unless the Commission provides otherwise. Finally, this restructuring rule modifies the terms of existing capacity brokering programs to conform to a generic capacity releasing program that incorporates many features of capacity brokering while addressing concerns about the discriminatory allocation of pipeline capacity.

IV. BACKGROUND

A brief history of the natural gas industry and its regulation puts the instant rulemaking in historical perspective, and shows that the rule is a logical outgrowth of the changes in both the industry and its regulation as they have evolved over the last fifty plus years.

In 1938, Congress enacted the NGA to regulate the sale for resale in interstate commerce of natural gas.[17] Congress' action stemmed from the Supreme Court's barring of state regulation of wholesales of natural gas[18] and from a 1935 report of the Federal Trade Commission (FTC).[19] The FTC report specifically referred to the "[u]nregulated control of pipe-line transmission and of wholesale distribution" as a "positive evil."[20] The FTC report described the significance of control over the pipelines as follows:

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17. 15 U.S.C. 717-717w (1988).

18. *See, e.g.*, Peoples Natural Gas Co. v. Public Service Commission of Pennsylvania, 270 U.S. 550 (1926).

19. Final Report of the Federal Trade Commission to the Senate of the United States pursuant to S. Res. 83, 70th Cong., 1st Sess. (1935).

20. *Id.* at 615.

Appendix B

> Whoever controls the channels by which a product is marketed controls the market so far as the supply is concerned. Concentrated control of those channels confers a strategic advantage that may be used by those possessing it to extend their domination into both the producing and distributing branches of the industry.[21]

In that light, Congress enacted the NGA because it "considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas."[22] Congress' "primary aim . . . was to protect consumers against exploitation at the hands of natural gas companies"[23] to ensure consumers "access to an adequate supply of gas at a reasonable price."[24] Congress, therefore, regulated the interstate chain of distribution of natural gas from the wellhead to market under a public utility model.[25] The "heart of the new regulatory system" was the "fixing of 'just and reasonable' rates"[26] for

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21. *Id.* at 591.

22. FPC v. Texaco, Inc., 417 U.S. 380, 397-398 (1974).

23. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944).

24. Tejas, *supra*, at 1003.

25. Mobil Oil Corp. v. FPC, 417 U.S. 283, 302-03 n.23 (1974).

26. FPC v. Hope Natural Gas Co., 320 U.S. 591, 611 (1944).

natural gas companies (both producers and pipelines) engaging in the sale for resale in interstate commerce of natural gas.[27] The structure of the natural gas industry regulated by the NGA was simple. The producers would sell their natural gas in the production area to the interstate pipelines at Commission-determined just and reasonable rates. The pipelines would transport their purchased gas and their own production to the city gate for sale to local distribution companies (LDCs) at Commission-determined just and reasonable rates which recovered both the pipelines' cost of gas and cost of transmission. In addition, the pipelines would sell gas to end users in nonjurisdictional sales with an appropriate allocation of costs to the nonjurisdictional services.[28] Producer sales to LDCs or end users in the production area, with the pipeline providing only the transportation, were rare. The central features of the NGA-regulated natural gas industry were Commission-determined just and reasonable prices and interstate pipeline sales of gas for resale to LDCs at the city gate at those prices in transactions that combined or bundled into one package the pipelines' gas supply and transmission costs.

The interstate natural gas shortages of the 1970s were the catalyst for reform of the regulation of the natural gas industry. Simply put, the Commission's struggles with producer rates did not prove adequate to the task of ensuring an adequate supply

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27. In Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), the Supreme Court held that the just and reasonable rate prescription of the NGA applied to the rates of gas producers. See also the discussion of producer regulation under the NGA in Public Service Commission of the State of New York v. Mid-Louisiana Gas Co., 463 U.S. 319, 327-331 (1983).

28. *See, e.g.*, Colorado Interstate Gas Co. v. FPC, 324 U.S. 581 (1945).

of interstate gas.[29] Hence, Congress responded to the natural gas shortages by enacting the NGPA to increase the flow of gas into the interstate market.

The NGPA created new statutory rates for the wholesale gas market, for so-called "first sales" of natural gas, in lieu of rates established by the Commission. Those new rates were "intended to provide investors with adequate incentives to develop new sources of supply."[30]

As part of the new rate structure, the NGPA also started the process of decontrolling wellhead prices of natural gas. Upon decontrol, NGPA Section 601 removed much of the pricing of the nation's natural gas supplies from the Commission's regulatory jurisdiction.[31] In addition, the NGPA, in Section 311, broke down the existing barriers between intrastate and interstate markets for natural gas. In that vein, Congress took action to promote gas transportation by interstate and intrastate pipelines by authorizing the Commission to approve certain transportation

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29. *See* Public Service Commission of the State of New York v. Mid-Louisiana Gas Co., 463 U.S. 319, 330-31 (1983). Commission established prices for gas in the interstate market could not compete with prices available in the intrastate markets where the prices were not regulated.

30. *Id.* at 334. In the NGPA, Congress eliminated this distinction between the interstate and intrastate gas markets.

31. *See* Pennzoil Co. v. FERC, 645 F.2d 360, 380-383 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); Associated Gas Distributors v. FERC, 824 F.2d 981, 1001 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988); *See also* Order No. 500-H, *supra* n.2, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 at p. 31,537-40 (1989).

arrangements outside of the NGA's certification requirements.[32] For example, NGPA Section 311(a)(1) authorized the Commission to approve the transportation of gas by an interstate pipeline on behalf of any intrastate pipeline and any LDC. In sum, the NGPA's aim was to permit a competitive wellhead market where market forces play a "more significant role in determining the supply, the demand, and the price of natural gas."[33]

The NGPA, therefore, radically changed a key aspect of the natural gas industry by eliminating Commission-determined prices for first sales of natural gas. In doing that, the NGPA "reflect[ed] the workably competitive nature of the production industry."[34] Moreover, the NGPA accelerated a fundamental change in the natural gas industry — "natural gas . . . [became] a separate and distinct economic *commodity*: distinct from oil, distinct from transportation, and distinct from storage and various load balancing services."[35]

In 1985, the Commission adopted Order No. 436[36] in

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32. Section 601(a)(2)(A) of the NGPA provides that the Commission does not have NGA Section 1(b) jurisdiction over NGPA Section 311 transportation.

33. Transcontinental Gas Pipe Line Corp. v. State Oil and Gas Board of Miss., 474 U.S. 409, 422 (1986).

34. Order No. 436, *supra* n. 2 at p. 31,470. *See also* Pennzoil Co. v. FERC, 645 F.2d 360, 378-79 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

35. *Id.* at pp. 31,472-73 (emphasis in original).

36. See n.2, *supra*.

response to the NGPA's aim to permit a more competitive wellhead market and to the economic changes in the natural gas industry.[37] Order No. 436 instituted open-access, non-discriminatory transportation to permit downstream gas users such as LDCs and industrials to buy gas directly from gas merchants in the production area and to ship that gas via the interstate pipelines.

To achieve open access transportation, Order No. 436 adopted three key regulations that are pertinent here. First, pipelines were required to permit their firm sales customers to convert their firm sales entitlements to a volumetrically equivalent amount of firm transportation service over a five-year period.[38] Second, the pipelines were required to offer their open-access transportation services without discrimination or preference.[39] Third, the pipelines were required to design maximum rates to ration capacity during peak periods and to maximize throughput for firm service during offpeak periods and for interruptible service during all periods.[40] Order No. 436 thus provided the downstream gas purchasers with an alternative to buying gas from the pipelines in the distribution area under the pipelines' bundled sales services.

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37. See the discussion in Order No. 436, *supra* n.2 at pp. 31,469-70 and 31,472-74.

38. 18 CFR 284.10.

39. 18 CFR 284.8(b) and 284.9(b). The pipelines could impose reasonable operational conditions to effectively manage their systems. 18 CFR 284.8(c) and 284.9(c).

40. 18 CFR 284.7(c)(1) and (2).

Appendix B

Order No. 436's open-access transportation program has accomplished, in part, its goals of increasing competition and treating the sale of gas and the transportation of gas as separate economic transactions. Two facts attest to the considerable success of Order No. 436. First, an active and viable spot market has developed for gas.[41] Second, the role of pipelines has changed from primarily merchants of natural gas in the distribution area to both merchants of natural gas and nondiscriminatory transporters of natural gas owned by others.

Indeed, pipeline transportation now accounts for about 79 percent of total annual interstate pipeline throughput.[42] This reverses the historical function of pipelines, which prior to Order No. 436 acted primarily as gas merchants.[43] Today, gas

41. See the Commission staff study in Interim Gas Supply Charges and Interim Gas Inventory Charges, Notice of Proposed Policy Statement, "Use of Spot Market Prices for Sales Service and Gas Inventory Charges", 47 FERC ¶ 61,294 Appendix at pp. 62,036-62,040 (1989) ("Staff concludes that the spot market is a well functioning market in the sense that it is broad and that prices do indicate its responsiveness to supply and demand[.]" *Id.* at p. 62,036).

42. Energy Information Administration/Natural Gas Monthly (Feb., 1992); DOE/EIA-0130 (92/02), From: Table 15. Natural and Other Gases Produced and Purchased by Major Interstate Natural Gases Pipeline Companies, 1985-1991 (around 80 percent transportation); Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1990 (July, 1991), From: Table A-1, Carriage for Distributors, End-Users, and Marketers and Sales Summary (79 percent transportation) (INGAA July 1991 paper). The updated INGAA paper shows transportation at 83 percent for the first half of 1991. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through the First Half of 1991 (November 1991), From: Table A-1 Carriage for Distributors, End-Users, and Marketers and Sales Summary (INGAA November 1991 paper).

43. In 1984, transportation amounted to 8 percent of the total gas carried to market by pipelines. INGAA November 1991 paper, *supra*, Table A-1.

transported on behalf of nonpipeline shippers plays a major role in providing service to customers, including service during the winter heating season.[44] The active spot market and significant pipeline transportation of gas owned by others illustrate that pipelines and other gas merchants, such as producers and marketers, are vigorously competing in the sale of gas to LDCs and other end users.

To repeat, the NGPA and Order No. 436 fundamentally changed two key components of the natural gas industry. First, the price of natural gas as a commodity was no longer subject to Commission-determined rates. Second, the transportation and sale of natural gas became distinct economic and commercial services. In that manner, pipelines and other gas merchants have become direct competitors in the sale of gas to LDCs and to end users, such as industrials or gas-fired electric generators.

In 1989, Congress built upon the significant changes in the natural gas industry shaped by the NGPA and Order No. 436 by enacting the Decontrol Act.[45] This legislation amended the NGPA "to repeal all remaining price controls on wellhead or 'field' sales of natural gas"[46] in order to obtain "more abundant [gas] supplies" at "lower prices" by creating competition among

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44. In the first quarter of 1990, sales gas amounted to 29 percent of total carriage delivered to market. In the first quarter of 1991, that figure was 21 percent. The remainder was gas carried to market for LDCs, for end users and for marketers. INGAA November 1991 paper, *supra*, Table A-1.

45. Pub. L. No. 101-60, 103 Stat. 157 (1989).

46. H. R. Rep. No. 29, *supra*, at p. 2.

a "set of efficient producers."[47] The House Committee Report stated that the Commission's "current competitive 'open access' pipeline system [should be] maintained" and further described the importance of open access transportation as follows:

> The Committee stresses that these new rules, and especially the wide adoption of blanket certificates for non-discriminatory open access interstate transportation of non-pipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies. [48]

The House Committee Report further urged the Commission "to retain and *improve* this competitive structure in order to maximize the benefits of decontrol."[49]

The Decontrol Act did not, however, alter the NGA's consumer protection mandate. Indeed, the House Committee Report stated:

> Though not protected by remaining wellhead

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47. *Id.* at 7.

48. *Id.* at 6.

49. *Id.* (Emphasis added).

> controls, consumers still have a stake in how FERC handles gas pipeline transportation issues and allocates gas costs. This legislation does not deregulate gas pipelines. . . . [50]

Similarly, the Senate Committee Report stated that "the purpose [of the legislation] is to promote competition for natural gas at the wellhead in order to ensure consumers an adequate and reliable supply of natural gas at the lowest reasonable price."[51] In addition, the Senate Report stated:

> While this bill decontrols the first sale of natural gas, it does not deregulate interstate natural gas pipelines. The term "first sale", as defined by section 2(21) of the NGPA, expressly excludes "the sale of any volume of natural gas by any interstate pipeline." A pipeline's obligation to serve its customers arises out of the Natural Gas Act and is not affected by the decontrol of first sale transactions under the NGPA. [52]

To sum up, in the evolution of the natural gas industry from passage of the NGA in 1938 to the passage of the Decontrol Act, the industry has been transformed from the "traditional" structure where "pipelines purchased gas from producers [at regulated prices] and transported that gas to consuming markets where it was resold to LDCs [at regulated prices] and end

50. *Id.* at 4.

51. S. Rep. No. 39, *supra*, at p. 1.

52. *Id.* at 9.

users"[53] to a new structure where "LDCs and industrial end users increasingly have utilized pipelines only to transport [at regulated rates] the gas that they purchase [at decontrolled prices] directly from producers and marketers."[54] Indeed, as stated above, the role of natural gas pipelines has changed significantly, since pipeline transportation services now account for 79 percent of pipeline throughput.[55] This is a significant reversal from the pipelines' pre-Order No. 436 primary role as merchants of a bundled sales service.

Hence, at present, pipelines compete with other sellers of natural gas for sales to LDCs and end users, such as industrials and gas-fired electric generators. However, under the present regulatory structure of the natural gas industry, those competitors move their gas through the pipeline network using mainly interruptible transportation service, which amounted to 51 percent of deliveries for market in 1990.[56] Most pipelines, on the other hand, sell their gas in the distribution area on a firm basis and, therefore, use the firm transportation embedded within their bundled, firm sales service to move their gas. The interruptible transportation used to move much of the gas competing with pipeline gas is, by definition, inferior to the firm transportation included within the bundled, firm sales service.

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53. *Id.* at 6.

54. *Id.*

55. INGAA November 1991 paper, *supra*, Table A-1.

56. INGAA November 1991 paper, *supra*., Table A-6, Sales and Firm and Interruptible Transportation as a Percentage of Total Deliveries for Market through First Half 1991. In the first half of 1991, interruptible transportation amounted to 52 percent of total deliveries for market. *Id.*

In addition, although competitors moved their gas through the pipeline network in 1990 using firm transportation amounting to 28 percent of total deliveries for market,[57] this firm transportation, as discussed below, is inferior in quality to the firm transportation embedded within the pipelines' bundled, city-gate, firm sales service. Simply put, the latter service has access to essential facilities and services, such as storage, that are not generally available to shippers currently using firm transportation. Hence, the natural gas industry has not completed its evolution to the point where all gas is shipped on even terms without regard to the identity of the supplier.

V. THE ANTICOMPETITIVE EFFECT OF THE CURRENT REGULATORY ENVIRONMENT AND PIPELINE SERVICES

The fundamental issue before the Commission is whether the current regulatory structure provides all gas sellers with the same opportunity to compete for gas purchasers. The Commission must examine the current pipeline sales services and firm and interruptible transportation services as well as its regulatory methods to determine whether they operate to give competitive advantages and disadvantages to the various participants in the natural gas industry. If the Commission concludes that its current regulatory structure and the current form of bundled pipeline services are unduly discriminatory and anticompetitive, and therefore unlawful under NGA Section 5,[58]

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57. *Id.* In the first half of 1991, firm transportation amounted to 31 percent of total deliveries for market. *Id.*

58. NGA Section 5(a) provides in pertinent part that:

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it *must* fashion a remedy that corrects the undue discrimination.[59] This remedial action must not undermine the quality or reliability of services received by the pipeline customers. For, as discussed below, it is vital that pipeline customers continue to have access to an adequate and reliable supply of gas when needed to meet the needs of gas consumers at all times.

In 1990, although 21 percent of pipeline deliveries to market were pipeline sales as opposed to transportation of gas,[60] a disproportionate amount of pipeline capacity was reserved for pipeline firm sales services. This is attested to by the fact that, in 1990, 51 percent of the pipeline deliveries to market used

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> Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. . . .

59. Office of Consumers' Counsel v. FERC, 783 F.2d 206, 236 (D.C. Cir. 1986).

60. INGAA November 1991 paper, *supra*, Table A-1. Table 1 to this (Cont'd)

interruptible transportation.[61] This considerable movement of gas by interruptible transportation shows that firm sales customers have not converted their firm sales entitlements to firm transportation service. According to INGAA, "[c]onversions of maximum daily quantity (MDQ) rights amounted to slightly over 24 percent, or 8.5 Bcf/day, for the . . . period [1988-1990]."[62] This is confirmed by the pipeline capacity reports filed with the Commission under Section 284.12 of the regulations. The 1991 Capacity Reports for major pipelines that made bundled sales show that over 60 percent of peak day capacity on major pipelines was reserved for pipeline firm sales service. This is shown by Table 2 below. For those same pipelines, as shown in Table 3, 1990-91 pipeline sales accounted for only 18.8 percent of total throughput.

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order sets forth pipeline "Sales Share as a % of Total Gas Delivered for Market" from 1984-1991. Most of the sales were firm sales.

61. INGAA November 1991 paper, *supra*, Table A-6. The remaining 28 percent of the throughput was firm transportation.

62. INGAA July 1991 paper, *supra*, at p. 3. INGAA further stated that "[o]f the 22 responding pipelines, none reported contract demand conversions prior to 1988." *Id.* n. 7. The Commission lifted the stay on the effectiveness of 18 CFR 284.10, which permits contract demand conversions, effective November 1, 1987. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 FR 35539 (Sept. 22, 1987), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,764 (1987).

Appendix B

Table 1

(Omitted here but submitted separately as Lodging Appendix).

Appendix B

Table 2

(Omitted here but submitted separately as Lodging Appendix).

Appendix B

While pipeline sales were less than 20 percent of total throughput on the major pipelines, during the three day period of peak usage, pipeline sales were approximately 50 percent of total deliveries (see Table 3). The seasonal nature of the pipeline sales indicates that customers rely on pipeline sales during periods when capacity is most likely to be constrained. For example, as Table 3 shows, approximately 85 percent of the sales Docket Nos. RM91-11-000 and RM87-34-065 by Tennessee Gas Pipeline Company and Williams Natural Gas Company occurred duirng the winter months. On many other pipelines 70 percent or more of their sales were made during the winter season, and overall approximately 65 percent of pipeline sales were made in the winter months. This is illustrated in Table 3.

Appendix B

Table 3

(Omitted here but submitted separately as Lodging Appendix).

The result is that while a large portion of pipeline capacity is reserved for firm sales, pipeline sales customers prefer to buy their gas from other sellers and have it transported using interruptible transportation. However, during peak winter periods pipeline sales predominate over sales by other gas sellers. The result is an inefficient market that disadvantages all segments of the gas industry as discussed further below.

Gas buyers are disadvantaged because they are paying the demand charges for firm pipeline sales service, and, in addition, paying the interruptible rates to transport gas purchased from other sellers. Instead of buying gas from the pipeline or converting to firm transportation, gas buyers are choosing to purchase gas from nonpipeline merchants and transporting the gas to market using an inferior form of transportation. As shown in Table 4, the price of pipeline gas generally has been 20 to 80 cents higher per Mcf than the price available from other sellers. Thus, it is often cheaper for pipeline sales customers to buy gas on the spot market, and pay the pipeline's demand charge plus the interruptible rate, than to purchase the pipeline's gas. This is inefficient and disadvantages customers because they must pay extra for the inferior interruptible transportation service even though it is used in lieu of firm transportation rights embedded within their bundled, city-gate, firm sales services.

Appendix B

Table 4

(Omitted here but submitted separately as Lodging Appendix).

Appendix B

The main reason that pipeline sales customers have not converted to firm transportation to satisfy their needs is that the transportation embedded within the pipeline's bundled city-gate, firm sales service is superior in quality to the pipeline's separately available firm transportation service. This is because, as the commenters opposing mandatory unbundling amply prove, the transportation embedded within the pipeline's bundled, city-gate, firm sales service is more reliable and flexible to meet their peak needs than the firm transportation service that is available to be combined with sales by nonpipeline merchants.[63] For example, firm transportation is less flexible than pipeline sales service because most firm transportation is subject to daily scheduling and balancing requirements that do not apply to sales service. In addition, a firm transportation shipper may be penalized if its daily swings vary by more than 10 percent from the amount the shipper scheduled for transportation, whereas sales customers do not pay penalties for variances from their projected purchases.

Under current circumstances pipeline sales service is more reliable because the pipelines' ability to make timely deliveries on demand is greater than their competitors' ability to do so. Simply put, the pipelines' bundled, firm sales service has available to it component services not available to firm transportation. For example, many pipelines have access to substantial storage capacity to aid their own sales, but many pipelines do not provide open access, contract storage services

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63. A comparison of the share of pipeline sales to total deliveries for market by quarters also attests to the superiority of pipeline bundled sales services. As shown in Table 1, pipeline sales in the first (January, February, and March) and fourth quarters (October, November, and December) are greater than their shares for the rest of the year.

for others.[64] This limits the firm shippers' ability to aggregate supplies for future use in a manner similar to the pipeline's aggregating ability.[65] In addition, pipelines entered into contracts with other pipelines for upstream capacity rights when the pipelines were providing very limited transportation services. Pipelines with those capacity rights on upstream pipelines are able to reach more producers than gas purchasers without that capacity.[66] Thus, the firm transportation service embedded within the pipelines' bundled, city-gate, firm sales service is superior to the pipelines' open access firm transportation service. This means that pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors.

The Commission believes that this lack of comparability between pipeline open access firm transportation service and pipeline bundled, city-gate, firm sales service is a major reason why pipeline customers have not converted to firm transportation service to a greater degree.[67] Indeed, the commenters opposing mandatory unbundling specifically cited the difference in quality

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64. Contract storage means that a pipeline customer has a contract with the pipeline which enables the customer to inject its own gas into and withdraw that gas from the pipeline's storage facilities.

65. See *infra* on storage.

66. See *infra* on upstream pipeline capacity rights.

67. Many commenters assert that until the issuance of Order No. 500-J, on February 13, 1991, uncertainty about the Commission's pregranted abandonment rule hindered conversions. See n.16, *supra*.

between pipeline firm sales and firm transportation as the reason why customers had not converted to firm transportation.[68]

This means that considerable firm capacity rights are restricted to pipeline sales gas and may not be used to move gas sold by others on a firm basis. Thus, gas sold by others must often move through interruptible transportation — which reduces its quality and value especially during peak demand periods.

The result is that nonpipeline gas sellers are also disadvantaged because they cannot compete for long-term supply arrangements since their access to superior firm transportation is artificially limited and their gas is therefore transported on an interruptible rather than a firm basis. This movement of gas sold by others via mainly interruptible transportation results in facially uneven competition between pipeline merchants and other gas suppliers because firm sales service is of a higher quality than interruptible transportation service by definition. Of necessity, this inhibits nonpipeline gas suppliers in their quest to secure long-term supply arrangements with LDCs and end users, such as industrials and gas-fired electric generators because, unlike the pipeline, those merchants cannot assure delivery at the city-gate in all circumstances. Simply put, the pipeline can interrupt its competitor's transportation service on reasonable notice when the pipeline needs the capacity for its own bundled, city-gate, firm sales service. Moreover, gas purchasers are inhibited from securing long-term supply arrangements with nonpipeline gas suppliers because the gas must often move through interruptible transportation, or at best inferior firm transportation.

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68. Reply Comments of United Distribution Companies (UDC) at 7 ("The remaining pipeline sales service is largely used to provide swing service during the winter months and therefore cannot be converted absent comparable transportation.").

Appendix B

While gas purchasers and nonpipeline sellers are clearly disadvantaged under current circumstances, pipelines are not the beneficiaries. Pipelines also are disadvantaged by the current environment. Pipelines have certificate and contractual obligations that require them to stand ready to provide gas on demand without notice. However, the pipeline's sales customers are under no obligation to buy gas from the pipeline. Compounding the pipelines' difficulty is that under existing regulations they cannot have the kind of pricing flexibility they need to price their gas to compete with unregulated sellers. As a result, pipelines have suffered a significantly declining share of the sales market since the adoption of Order No. 436.[69]

The Commission believes that the primary reason for this is the way that pipelines sell their gas. Pipelines are allowed to earn only a regulated return on their transportation business. Because pipelines sell gas bundled with a transportation service over which they possess market power, the Commission requires pipelines to sell their gas at cost to ensure that pipelines cannot shift the recovery of monopoly profits from their transportation service to the sale of the, now deregulated, commodity. The cost-based rate at which the Commission has required the pipelines to sell their gas is their weighted average cost of gas (WACOG). The Commission does not permit a pipeline to sell gas at a market rate unless the pipeline demonstrates that its sales markets are sufficiently competitive to prevent it from exercising significant market power. To make its case, the pipeline must show that its firm transportation service is comparable in quality to the firm transportation embedded within its firm sales service[70] and that

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69. See Table 1.

70. *E.g.*, United Gas Pipe Line Co., 55 FERC ¶ 61,330 at p. 61,974 (Cont'd)

adequate divertible gas supplies exist in its sales markets.[71] Most pipelines have not switched from cost-based, WACOG pricing to market-based pricing. Therefore, they are at a disadvantage when competing with the unregulated, market-based pricing of other merchants in the gas supply market. Because recently the WACOG has been above the spot gas price, pipeline customers often choose to buy their gas elsewhere and ship it under the pipelines' interruptible transportation services.[72]

In sum, under the current situation pipelines are disadvantaged in selling gas through WACOG pricing, customers are disadvantaged by using interruptible transportation in addition to paying the demand charges for firm sales, and nonpipeline sellers are disadvantaged because their gas must move mostly with interruptible transportation.

Based upon the record here and the Commission's observations of the gas industry since the advent of open-access

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(1991) ("United must specifically demonstrate that its transportation services and storage services available to firm transportation customers are comparable to the transportation and storage in its bundled service offered at market-based rates.").

71. The Commission has found that a pipeline's sales are made in a sufficiently competitive market when the pipeline provides comparable transportation service with respect to all gas supplies from whomever purchased and when adequate divertible gas supplies exist. *E.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

72. See Table 4.

transportation, the Commission believes that the main reason for this current situation, which disadvantages all segments of the natural gas industry, is the continued existence of the pipelines' bundled, city-gate, firm sales service. This service reserves a considerable amount of pipeline capacity throughout the year in order to ensure peak service. Hence, pipelines must sell at their WACOG throughout the year and gas purchasers must use a considerable amount of interruptible transportation to acquire competitively priced gas from other gas sellers. In addition, the pipelines' existing bundled, city-gate firm service gives pipelines an undue competitive advantage over other natural gas suppliers in making peak sales because nonpipeline merchants must deliver gas to their customers using inferior firm and interruptible transportation services.

The bundled, city-gate firm sales service gives pipelines an undue competitive advantage *vis a vis* other gas merchants that is not in the public interest as described by Congress in enacting the Decontrol Act. Pipeline transportation of its own gas on superior terms over the transportation (mainly interruptible) of other supplies will inhibit the "unimpeded transmission of market signals" and the "unimpeded operation of market forces" so that gas purchasers and sellers will be forced to make decisions in "distort[ed] natural gas markets" because of "erroneous market signals".[73] Over the long-run, this uneven transportation will, therefore, inhibit the production of an adequate supply of natural gas at reasonable prices and retard the nation's ability to reduce its dependence on foreign oil and to solve environmental problems by greater use of clean and abundant domestic natural gas.[74]

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73. S. Rep. No. 39, *supra*, at p. 2.

74. *Id.* and H.R. Rep. No. 29, *supra*, at p. 2.

Appendix B

The pipelines' bundled, city-gate, firm sales service, therefore, has a harmful impact on competition between pipelines and other gas merchants, on the creation of a national wellhead market for gas where consumers will have access to an adequate supply of gas at reasonable prices, and on the nation's need to rely more on clean and abundant domestic natural gas. However, the Commission realizes that the pipelines' bundled, city-gate, firm sales service has the objective of providing a "no-notice" service where firm sales customers can receive gas up to their daily contract entitlements on demand without nominating that amount or incurring a penalty.[75] The delivery of supplies on a "no-notice" basis is in the public interest because it enables pipeline customers to meet unexpected changes in peak service needs caused, for example, by an unexpected change in temperature.

In evaluating a "rule, regulation, practice, or contract,"[76] the Commission "must carefully balance the competitive harm the term causes against the term's objectives in light of the alternatives available for achieving those objectives."[77] In this instance, the "term" upon which the Commission has focused

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75. The Commission understands that the pipeline and its customers are in close communication throughout the day. Nonetheless, the existing sales customer is not bound by any initial nominations or updated nominations.

76. NGA Section 5(a), *supra*.

77. Transwestern Pipeline Co., 36 FERC ¶ 61,175 at p. 61,439 (1986), *aff'd*, Transwestern Pipeline Co. v. FERC, 820 F.2d 733 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988) (The court affirmed the Commission's elimination of Transwestern's fixed cost minimum bill as not justified in view of its competitive harm.).

is the pipelines' bundled, city-gate, firm sales service and its impact on the current competitive environment. The Commission will strike down or alter a contract as an unreasonable restraint of trade "[o]nly if on balance the term causes more harm than is warranted in light of the term's objectives and the available alternatives[.]"[78]

Based upon the extensive record developed in this entire proceeding,[79] as well as the Commission's observations of the industry, the Commission finds that the pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry as described above. The Commission finds that this harm has an unreasonable impact on gas sellers and gas purchasers and is an unlawful restraint of trade which is not balanced by the "no-notice" aspect of the bundled, city-gate sales service because, as fully discussed below, the pipelines can and will be able to provide a "no-notice" transportation service for all gas supplies without the competitive harm attendant to the current bundled, city-gate, firm sales service. Restricting access to a "no-notice" service by limiting its availability to the purchase of pipeline sales gas is anticompetitive. The bundled, city-gate, firm sales service provides the pipelines with an undue advantage and subjects other gas merchants to an undue disadvantage. It maintains an

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78. *Id.* (The Commission found that "Transwestern's minimum bills caused more harm than was warranted . . . [and] concluded that the minimum bills unreasonably restrained trade and hence were unjust and unreasonable.").

79. As discussed, *infra*, the Commission received comments in connection with a May 10, 1991 public conference, the Notice of Proposed Rulemaking, issued July 31, 1991, and a technical conference held on January 22, 1992.

unreasonable difference in service between classes of service (bundled, city-gate, firm sales and open access firm transportation) because the firm transportation embedded within the firm sales is superior in quality as discussed above. The Commission, therefore, finds and concludes that the pipelines' bundled, city-gate, firm sales service violates NGA sections 4(b) and 5(a).

The Interstate Natural Gas Association of America (INGAA) disputes the Commission's conclusion that the pipelines' bundled, city-gate, firm sales service is anticompetitive. INGAA states that "pipeline bundled sales service is not an impediment to the sellers of firm sales service and therefore is not anticompetitive."[80] INGAA refers to its 1990 numbers which show that "firm transportation volumes for non-pipeline shippers accounted for 28 percent of total volumes delivered for market compared with pipeline sales of 21 percent."[81] INGAA states that this demonstrates that "pipelines are no longer the dominant providers of the merchant service."[82]

As discussed above, the Commission believes that this decline in pipeline sales is due to their selling gas under cost-based, WACOG pricing of the bundled, city-gate, firm sales service. Moreover, INGAA fails to note the fact that firm sales customers have not reduced their sales CD entitlements by nearly as much as they have reduced their purchases.

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80. Initial Comments at 8.

81. *Id.* at 9.

82. *Id.*, quoting INGAA July 1991 paper, *supra*, at p. 1.

Appendix B

The Commission draws a different conclusion from INGAA's numbers with respect to long-term gas supply arrangements and sales to meet the peak needs of gas purchasers. The Commission concludes that in those situations the pipelines have a competitive advantage because the firm transportation embedded within their bundled, city-gate, firm sales service is superior in quality to both the firm transportation and the considerable amount of interruptible transportation used to move gas sold by nonpipeline merchants to LDCs and end users, such as industrials and gas-fired electric generators.[83] In particular, the Commission finds that the pipelines have an undue advantage over their merchant competitors in securing long-term gas supply arrangements with customers because, as discussed above, the pipelines currently have a superior ability to deliver gas on demand to meet the peak needs of LDCs and other customers. For example, the pipelines have access to storage to meet the customers' needs on demand.[84] In general, nonpipeline merchants have not been able to obtain access to storage for the gas that they sell because the Commission has not required the pipelines to offer open access contract storage.[85] The pipelines'

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83. Interruptible transportation amounted to 51 percent of total deliveries for market in 1990. INGAA November 1991 paper, *supra*, Table A-6.

84. Withdrawals from storage are significantly greater during peak months than during offpeak months. Energy Information Administration/ Monthly Energy Review (Feb., 1992); DOE/EIA-0135 (92/02), From: Table 4.2, Natural Gas Supply and Disposition; Energy Information Administration/ Natural Gas Monthly (Feb., 1992); DOE/EIA-0130 (92/02), From: Table 18, Underground Natural Gas Storage — Interstate Operators of Storage Fields, 1985-1991.

85. See *infra* on storage.

competitive advantage *vis a vis* the needs of gas purchasers at peak is shown by the significantly increased share of pipeline sales to total deliveries for market in peak quarters over nonpeak quarters, and by the significantly higher prices they receive for gas (see Table 4). In 1989-1990, the percentage of pipeline sales in peak quarters was double its share in offpeak quarters,[86] and in 1990-91 two-thirds of pipeline sales were in the winter months (see Table 3). Thus, the Commission draws a different conclusion from INGAA's numbers.

The Commission finds that the pipelines' bundled, city-gate, firm sales service gives pipelines an undue advantage over other gas sellers because of the superior quality of the "no-notice" aspect of the transportation embedded within the bundled, city-gate, firm sales service when compared to the firm and interruptible transportation available for the gas of nonpipeline gas sellers. The Commission understands the counter argument made by the pipelines. That is, unless they are relieved of their service obligation to their firm sales customers, they must maintain the ability to serve those customers at peak. As noted above, their firm sales customers do not buy most of their gas from the pipelines, but the pipelines must be ready to serve them by selling gas to them during periods of peak demand. This situation is the nub of the service obligation problem that the Commission is addressing in this order. In order to secure a more efficient marketplace, the Commission must address the lack of equality in transportation (and storage) services, the pipelines' dominance in the peak period sales, the lack of flexibility in pipelines' sales pricing, and the pipelines' remaining service obligation simultaneously.

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86. See n. 63, *supra* for a comparison of pipeline sales for peak and offpeak quarters.

Appendix B

The Commission recognizes that over the past several years, the pipeline industry has been moving toward improving the quality of firm transportation and storage services available to competing sellers. However, the amount of capacity reserved for pipeline firm sales still far exceeds the pipelines' actual sales so that capacity is not available for firm transportation and, as a result, interruptible transportation maintains a significant share of peak period transportation. Thus, competing sellers continue to be at a disadvantage. In addition, firm transportation service is still subject to many more restrictions than necessary as compared to pipeline bundled firm sales service. Therefore, although the trend in the industry has been moving toward more even competition, the Commission finds it necessary to act here to accelerate and complete the transition toward a more efficient market.

In sum, the Commission believes that all segments of the natural gas industry are unduly disadvantaged by the current regulatory structure of the industry. The Commission must, therefore, act under NGA section 5 to determine the just and reasonable "rule, regulation, practice [and] contract[s]" to be "observed and in force".[87]

VI. THE REMEDY

A. The Remedy Proposed in the NOPR

Having found the current regulatory structure leads to unjust and unreasonable results, the question remains what the appropriate remedy is to address this situation. On July 31, 1991, the Commission proposed changes to its regulation of

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87. NGA Section 5(a), *supra*.

interstate natural gas pipelines to remedy the pipelines' undue competitive advantage.[88] The July 31 Notice of Proposed Rulemaking (NOPR) was, among other things, the outcome of a public conference held on May 10, 1991, where members of the natural gas industry discussed with the Commission the role of interstate natural gas pipelines in today's natural gas markets.[89]

In brief, the NOPR proposed to amend Part 284 of the Commission's regulations [90] as follows:

° Pipelines would be required to unbundle (*i.e.*, separate) their sales and transportation services with one exception for continued bundled sales to small customers. Pipelines would, however, be allowed to repackage their unbundled services to replicate their bundled, city-gate, sales services.

° The definition of transportation would be amended to include storage so that storage would be provided on an open access contract basis.

° Pipelines would be required to provide an open access transportation service that is comparable in quality for all

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88. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 FR 38372 (Aug. 13, 1991), IV FERC Stats. & Regs. ¶ 32,480 (1991).

89. All future references to pipelines are to interstate pipelines. Except for expanding the Part 284 definition of transportation to include storage, the regulations adopted by this order do not apply to intrastate pipelines.

90. 18 CFR Part 284.

gas supplies, whether purchased from the pipeline or elsewhere.

° Firm transportation customers of downstream pipelines would be assigned capacity on upstream pipelines now held by downstream pipelines.

° Pipelines would be required to implement a capacity releasing program.[91]

° Pipelines would be granted blanket certificates for unbundled sales services and would be subject to standards of conduct in connection with unbundled sales services similar to those applicable to affiliate sales.[92] The unbundled sales services would be subject to pregranted abandonment.

° Pipeline transportation rates would be designed under the Straight Fixed Variable method unless the parties to a proceeding otherwise agree (however, measures would be permitted to mitigate cost shifts, if necessary).[93]

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91. The NOPR proposed that capacity brokering certificates be individually terminated.

92. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec. 22, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. & Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992).

93. Straight Fixed Variable is defined *infra*.

° Pipelines would be required to initiate restructuring discussions with all interested parties within 30 days of the effective date of the Final Rule and to file a restructuring plan on or before the required date set forth in the regulations. Prior to the effective date of a restructuring filing, the holders of firm capacity would be required to exercise a right of first refusal by giving notice that they want to continue their contractual arrangement and that they agree to match and pay any greater rate up to the maximum rate and to match the most favorable contract term offered by others seeking firm capacity.

B. Comments on the NOPR

The NOPR proposed to require pipelines to unbundle (*i.e.*, separate) their sales and transportation services with one exception for continued bundled sales to small customers. A substantial number of commenters from all segments of the natural gas industry support the NOPR's mandatory unbundling proposal.[94] However, a substantial number of pipeline and LDC commenters oppose mandatory unbundling.[95] In brief, they state that, on some pipelines, a bundled, city-gate, firm sales service is necessary so that pipeline customers can receive service on demand to meet unexpected changes in peak service needs

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94. *E.g.*, Natural Gas Supply Association and Indicated Producers (NGSA), Independent Petroleum Association of America (IPAA), Transcontinental Gas Pipe Line Corporation, Consolidated Edison Company of New York, Inc., and the Public Service Commission of the State of New York.

95. *E.g.*, Interstate Natural Gas Association of America, Coastal Companies, Distributors Advocating Regulatory Reform (DARR), and Cincinnati Gas and Electric Company.

caused, for example, by an unexpected change in temperature. This is known as "no-notice" service.[96]

In addition, it is stated that pipelines will not be able to provide instantaneous transportation service if they must unbundle their sales and transportation services.[97] Instantaneous service occurs when the pipeline delivers gas to its downstream customer when the gas is injected into the pipeline upstream. This differs from "no-notice" service where a pipeline customer can take delivery without regard to injections into the pipeline system at the same time.

On January 22, 1992, representatives from all segments of the natural gas industry discussed with the Commission at a technical conference issues with respect to the operational aspects of the NOPR. In connection with that conference, interested persons filed written responses to questions posed by the staff in the appendix to the notice of the technical conference.[98] The information obtained at the technical conference, as well as from the initial and reply comments to

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96. The firm sales customer may purchase gas up to its firm daily contract entitlement without incurring a penalty and even though the customer and the pipeline are in close communication, the customer is not bound by any initial nominations or updated nominations.

97. Initial Comments of Texas Eastern Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, and Algonquin Gas Transmission Company (PEC Pipeline Group) at 16-17.

98. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 57 FR 385 (Jan. 6, 1992).

the NOPR,[99] has been very helpful to the Commission in fashioning the final rule. The Commission has evaluated all the comments received but specifically addresses below only those that opposed the action adopted in this final rule. Comments that addressed proposals in the NOPR that are not adopted in this final rule are not specifically addressed, nor are comments that raised issues not relevant to the decisions reached here.

C. Remedial Action in the Final Rule

The question is what remedial action is appropriate to counter the pipelines' undue advantage as merchants providing bundled, city-gate sales service while retaining the reliable, "no-notice" service for pipeline customers that want such a service. As stated above, the NOPR proposed to eliminate the bundled, city-gate, sales service with an exception for small customers, and recognized that pipelines could package their various services to achieve the equivalent of a bundled, firm sales service.

Significantly, the representatives of the pipeline industry participating in the technical conference indicated a significant shift in their position from that stated in the written comments. Initially, the pipelines took the position that the bundled, city-gate, firm sales service is essential to the providing of "no-notice" and instantaneous service. However, at the technical conference they acknowledged that pipelines can provide those services for the delivery of any shipper's gas if permitted to retain adequate operational control of the use of their facilities.[100]

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99. The Commission has accepted and considered all comments filed, including late-filed comments.

100. *E.g.*, compare INGAA Initial Comments at 3,4 and Technical Conference Tr. 36-38.

Indeed, the information received at and after the technical conference reveals that a significant majority of the public — cutting across all segments of the industry — share and support this proposition.

The comments received at the technical conference highlighted several important matters. First, unbundling should have no perceptible effect on the reliability of a pipeline's peak day delivery services for heat sensitive residential loads. Second, the Commission, most pipelines, producers, most LDCs, marketers, and industrials agree that the pipeline should maintain operational control of the pipeline facilities, but importantly, in a manner that does not constitute any compromise of nondiscriminatory, fully equal, transportation services. Third, there are a number of operating and contractual tools to ensure that the pipeline, its customers and its shippers will take the necessary actions to maintain the reliable operation of the system — and those tools are not theoretical or speculative. They are in use today on the El Paso, Northwest and Transco systems and they have been proposed for the Northern Natural system. The details would be among the issues that would be worked out in the restructuring proceedings. Fourth, the comments strongly evidence that current pipeline services, in fact, can be unbundled into separate transportation, storage, and balancing services with complete equality of treatment for all gas supplies, price transparency and without cross-subsidization so that customers are offered a menu of unbundled services. And, fifth, there is general agreement that *one* form of bundled transportation service that can be offered would be the no-notice peak service on which some LDCs continue to claim reliance, with either pipeline or nonpipeline supplied gas.

The Commission has shaped this rule, in part, in response

to those comments by creating a new "no-notice" firm transportation service under which gas customers will be able to receive gas up to their daily contract entitlement without incurring a penalty (see *infra* for a discussion of "no-notice" transportation service). In light of the views expressed at the technical conference, the Commission is confident that the pipelines can unbundle their services and, by retaining operational control of their systems, transport gas, whether purchased from a pipeline or nonpipeline supplier, on a basis that is just as adequate and reliable as the current bundled, city-gate, firm sales service in meeting the needs of their customers and of gas consumers.

Therefore, the final rule adopts the remedial approach of the NOPR. The Commission finds that it is appropriate to require pipelines to unbundle their sales services from their transportation services at an upstream point near the production area. To accomplish this required unbundling, the Commission is using its authority under NGA section 5 to convert each pipeline's bundled, city-gate, firm sales service into an unbundled firm transportation service. The existing bundled city-gate service obligation is being supplanted through the procedures established by this rule. In its place, pipelines and their existing sales customers will be able to negotiate a new unbundled firm sales service to be performed under a new blanket sales certificate for all pipelines offering open access transportation under Subpart B or G of Part 284 of the Commission regulations, as discussed in greater detail below. After negotiation of a new sales agreement, the pipeline's obligation to sell gas to that customer will be co-extensive with that new agreement. As an additional remedy, the Commission is affording firm sales customers the opportunity during the restructuring proceedings established by this rule (see *infra*) to

reduce their unbundled firm sales entitlements in whole or in part. This will enable those customers to freely negotiate to purchase gas from the pipeline under its new market-based sales service or to purchase gas from other gas suppliers. The end result will be that all gas will move from the production area to the city gate under firm or interruptible transportation service.

The NOPR referred to the possibility of unbundling at the wellhead, at production area receipt points into mainline facilities, at receipt points, at the intersection of separate mainline systems, or at several of those places. In addition, the NOPR recognized the use of pooling areas as a means to facilitate the aggregation of supplies by all merchants. Most commenters support the Commission's proposal to determine places of unbundling on a case-specific basis and not to mandate pooling areas. A few commenters suggest specific places for unbundling[101] while other commenters urge the Commission to mandate pooling areas.[102]

The Commission concludes that the precise places of unbundling should be determined in the restructuring proceedings established by this order. The Commission believes it would be unwise to mandate specific unbundling places for the pipeline industry in light of the different configurations of the pipelines and their sources of supply. However, the place of unbundling should be located as far upstream as possible.

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101. *E.g.*, Tejas Power Corporation states that unbundling should take place at the wellhead while the American Paper Institute states that unbundling should occur at mainline receipt points.

102. *E.g.*, the Independent Petroleum Association of America, Natural Gas Clearinghouse, Brymore Energy, Inc., Vesta Energy Company, and the Natural Gas Supply Association/Indicated Producers.

Similarly, as discussed below, the Commission encourages but will not mandate the establishment of market centers and pooling areas.

The Commission discussed above the pipelines' "no-notice" service where bundled, firm sales customers can receive gas up to their daily contract entitlement on demand without nominating that amount or incurring a penalty. The Commission finds that it is in the public interest for pipelines to provide a firm transportation service that is a "no-notice" service similar to that received under the bundled, city-gate, firm sales service. Therefore, the Commission is requiring all pipelines that make sales for resale on the effective date of this rule to offer in their tariffs a "no-notice" firm transportation service. This service must be available as of the effective date of the tariff sheets to be filed to comply with this rule. This service, discussed in more detail *infra*, must be available to all firm shippers. The mechanics of how this "no-notice" firm transportation service will be provided on a particular pipeline must be considered and developed in the restructuring proceedings established by this rule (see *infra*).

This new "no-notice" transportation service will be provided in addition to, rather than in lieu of, the pipelines' current open-access, firm transportation service where shippers must receive instantaneous but not "no-notice" service. The former "traditional" firm transportation service will still be subject to reasonable nominating, scheduling and other operational conditions, such as imbalance tolerances and penalties. However, the quality of this service should be enhanced under the steps taken here. These operational conditions, of course, must be devised and implemented on a nondiscriminatory basis. In assessing the pipeline's compliance filing, the Commission

will seek to ensure that the pipeline is not attempting, through the "no-notice" transportation service, to simply replace one form of bundled service with another anti-competitive service.

In addition, the pipeline, or another gas merchant, could offer a "packaged" sales and transportation service where the separately sold sales and transportation services are packaged by a contract pursuant to which the gas purchaser allows the pipeline, or another gas merchant, to act as the gas purchaser's agent in making all arrangements necessary to deliver the gas to the city gate.[103] However, the rates for each transportation service must be separately stated in the pipeline's tariff.

Since sales and transportation services must be offered on an unbundled basis, there would be no rate on file with the pipeline's tariff for an "agency" service. The "packaging" of separate services, offered under separate rate schedules, would be effected only by contracts between the gas purchaser and its agent. Whether or not the pipeline as a gas seller can collect a fee for acting as the gas purchaser's agent in arranging for pipeline services is a matter for negotiation between the pipeline and gas purchaser on entering into their sales contract. This is because the pipeline will be acting as agent in its capacity as a gas seller rather than as a gas transporter. Any agency fee would have to be recovered as part of the price for selling gas and not as part of the transportation rate. Of course, the pipeline must act in a non-discriminatory manner in offering agency services.

The Commission is not adopting the NOPR's proposal to continue a bundled, city-gate, firm sales service for small sales

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103. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991).

customers, because those customers can be served reliably through a combination of unbundled sales and the "no-notice" transportation service required by this rule. The pipeline or another gas seller could also act as the agent of the small customers and make all of the arrangements necessary to deliver the gas to the small customers in the same manner as under the current bundled, city-gate, firm sales service. In addition, as discussed further below, the small customers can continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined.[104] Alternatively, as indicated by Florida Cities at the January 22, 1992 technical conference, small customers can band together to purchase gas.[105]

The Commission sees several reasons for requiring the unbundling of pipeline services and the creation of a "no-notice" transportation service, as opposed to retaining the pipelines' bundled, city-gate, sales service.

First, firm shippers will be able to select the form of pipeline transportation service that best suits their needs, both as to the quality and the prices of the individual services chosen. As stated, firm shippers will be able to choose a transportation service that provides "no-notice" service. In the alternative, firm

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104. Existing small sales customer rates are often determined by assuming a quantity of purchases which may be higher than actual purchases. Small customers, therefore, pay less for their service than they would if their rates were designed based on actual purchase levels.

105. Technical Conference Tr. 277,293. In Florida, several municipal utilities banded together with one utility buying on behalf of the others. The Florida Cities representative reported that those utilities have achieved "tremendous economies." *Id.* at 291.

shippers may elect a service of a different quality. For example, firm shippers can elect to continue the traditional open-access firm transportation service, if they do not want "no-notice" service. Or, firm shippers could purchase some combination of services, such as traditional firm transportation service and open-access contract storage. This complete menu of services will enable gas purchasers, sellers, and pipelines to fashion arrangements according to the demand for the services in lieu of the present system which binds individual services with separate costs together into one package. The gas purchaser, or nonpipeline seller will be able to make informed choices about services and the market will decide the need for the various services.

Moreover, the unbundling of pipeline services will enable all gas sellers (producers/marketers/pipelines) to compete on an even basis by offering the same sales services in the same market. At present, most pipeline sales are at the city gate at the WACOG price while most producer or marketer sales are at the wellhead or in the field at the market price. The unbundling of services will create competition for gas purchasers among gas merchants on more even terms. The competition for gas purchasers will not be skewed in favor of pipelines by their ability to offer a superior bundled, city-gate, firm sales service or against pipelines because of WACOG pricing. In addition, the competition between pipelines and other gas sellers in the same market should greatly reduce the pipeline's natural incentive in a bundled service environment to manage its pipeline system to favor itself as a merchant to the disadvantage of shippers of gas sold by others.

The Commission also believes that this new form of "no-notice" transportation service will be superior to the existing

"no-notice" bundled, city-gate, firm sales service. This is because gas purchasers will be able to obtain "no-notice" transportation service for gas supplies purchased from any gas seller, not just from pipelines, rather than relying on inferior firm or interruptible transportation as discussed above.[106] This should enable gas purchasers to enter into more reliable supply arrangements with nonpipeline suppliers for both base and peak needs. Hence, gas purchasers will have more choices and more flexibility. In addition, the pipelines will be able to compete for more gas purchasers under market-based pricing in lieu of their WACOG pricing.

Some commenters argue that the Commission's fostering of competition cannot be a justification in and of itself for the regulations adopted here. Rather, they contend that the Commission is required to foster competition only when consumer interests are advanced and protected.[107] The Citizens Gas & Coke Utility sees nothing wrong with unequal competition so long as the merchants' differing products are appropriately priced. It maintains that "[t]he Commission should *not* mandate a homogeneous group of sellers."[108]

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106. Even if the sales customer elects to continue to contract for its gas needs with the pipeline under a market-based rate that includes a component that compensates the pipeline for standing ready to provide a certain quantity of gas at all times, the customer will have the right to purchase spot gas elsewhere and use its unbundled firm transportation to ship it.

107. *E.g.*, the Cincinnati Gas & Electric Company, Union Light, Heat and Power Company, and Lawrenceburg Gas Company, Initial Comments at 13, 14, *citing*, Brown Shoe Co. v. U.S., 370 U.S. 294, 320 (1962) and Environmental Action, Inc. v. FERC, 939 F.2d 1057, 1061 (D.C. Cir. 1991).

108. Initial Comments at 7.

Appendix B

The Commission is not acting to protect competitors. Rather, the Commission, as discussed in detail above, is acting to improve the competitive structure of the natural gas industry to facilitate the operation of a national wellhead market as envisioned by Congress in order to provide natural gas consumers with access to an adequate supply of clean and abundant natural gas at reasonable prices. Moreover, the Commission is improving this competitive structure without undermining the reliability of service for pipeline customers by requiring pipelines to perform a "no-notice" transportation service. In short, the Commission is both promoting competition and protecting all gas consumer interests, especially with respect to the reliability and the pricing of services.

In addition, the Commission is not mandating a homogeneous group of gas merchants. Rather, the Commission is creating a regulatory environment that will provide all gas merchants with an equal opportunity to compete for gas purchasers. To be sure, not all gas sellers are similar. Some are more efficient than others. Some have greater expertise and some have more resources upon which to draw. However, by separating the various pipeline services needed by gas consumers, the Commission can assure the fair pricing of all services. The gas purchasers will be better off because of the ability to make informed choices about their gas purchasing decisions. Moreover, the rule will not change inherent advantages held by any gas merchant, whether it be a producer, marketer, or pipeline, on account of size, experience, or motivation. The Commission envisions a future gas market where buyers and sellers can meet to fashion deals according to their needs, with no decline in, and indeed with enhancement of, the quality and reliability of service for gas consumers.

To that end, the Commission is amending Part 284 in several ways to upgrade pipeline services used to transport gas, whether sold by a pipeline or another merchant. This will provide all gas purchasers with improved access to all gas sellers whether or not the gas purchasers want a "no-notice" firm transportation service.

In brief, the Commission is making ten changes in Part 284. First, the Commission is revising Sections 284.8(a)(1) and 284.9(a)(1) to require firm and interruptible transportation services to be provided unbundled from firm and interruptible sales. This requirement also will be included as a condition on the blanket sales for resale certificates issued by this rule and discussed *infra*. Second, the Commission is adding Sections 284.8(b)(2) and 284.9(b)(2), which require a pipeline that offers firm and interruptible transportation services under Part 284 to provide those services on a basis that is equal in quality for all gas supplies whether purchased from the pipeline or another seller. Third, and fourth, the Commission is adding Sections 284.8(b)(3), (4), and (5) and 284.9(b)(3), (4), and (5) to require a pipeline to provide all shippers equal and timely access to certain information through the use of electronic bulletin boards, and to preclude any tariff provisions that would inhibit the development of market centers. Fifth, the Commission is amending Section 284.1 to define transportation as including storage. Sixth, the Commission is adding Section 284.242 to authorize and require open access pipelines to provide firm shippers on downstream pipelines with non-discriminatory access to capacity held by the downstream pipelines on upstream pipelines. Seventh, the Commission is adding Section 284.243 to authorize a new firm capacity reallocation program so that firm shippers can release unwanted capacity to those desiring capacity.

Eighth, as discussed above, the Commission is adding Section 284.8(a)(4) to require pipelines that make bundled sales on the effective date of this rule to provide a non-discriminatory "no-notice" firm transportation service. The "no-notice" transportation service as well as the other matters pertinent to open access transportation, will be discussed in Part VII.

Ninth, in order to further promote even competition among gas merchants, the Commission is adopting the straight fixed variable method of cost classification for the purpose of billing firm transportation customers unless the Commission provides otherwise. Under that method, all of a pipeline's fixed transmission and storage costs are billed in the pipeline's reservation charge.

Tenth, the Commission is issuing in this rule a blanket sales certificate to all pipelines so that they can make unbundled firm and interruptible sales on a comparable basis with unregulated merchants (*see infra*). This appears as a new Subpart J to Part 284.

Last, the Commission is also reemphasizing, as discussed fully below, the policy stated in Sections 284.221(g) and (h) of its regulations that pipelines allow shippers to have flexible receipt and delivery points.

The Commission believes that the above-described remedial approach will both improve the competitive structure of the natural gas industry, by putting pipelines, when acting as merchants, and other gas merchants on an even footing with respect to essential pipeline services and will maintain the ability of the pipeline system to provide reliable service when needed — regardless of the source of the gas. All of the above remedial

acts are discussed in detail below. In tandem with these changes the Commission has concluded that pipelines should be able to recover 100 percent of their prudently incurred costs associated with implementation of this rule. This is also discussed in detail, *infra.*

Based upon the extensive record compiled in this proceeding, the Commission believes that the above-described unified and comprehensive remedy will benefit all segments of the natural gas industry. To the extent members of the industry are currently facing an uncertain financial situation, the Commission believes that this rule will remove that uncertainty and create a regulatory framework that can adapt to changing market dynamics over the long-run. Indeed, this rule will establish an efficient gas market in which all participants are able to fashion the contractual arrangements — both long and short term — best suited to their needs. In short, they will be able to respond to their financial and commercial situation through the contracting process in an efficient gas market.

VII. ESSENTIAL ASPECTS OF, AND TERMS AND CONDITIONS FOR, OPEN-ACCESS TRANSPORTATION

A. Introduction

The Commission adopted Order No. 436 to prevent pipelines from discriminating in their choice of transportation customers in order to favor the pipelines' own sales services.[109] The Commission codified this anti-discrimination purpose in

109. Order No. 436, *supra* n.2 at p. 31,495 ("Examples of discrimination that the Commission finds to be undue or preferential within the context of self-implementing authorizations are refusals to transport for existing sales or non-fuel switchable customers and preference for affiliates.").

Sections 284.8(b) and 284.9(b) by requiring pipelines to offer their firm and interruptible transportation services "without undue discrimination" in the quality of service provided.[110] At the same time, the Commission recognized that pipelines need to impose "reasonable operational conditions" on their services to effectively manage their systems and Sections 284.8(c) and 284.9(c) permit this, provided the conditions are included in the pipeline's tariff.[111] In evaluating those operational conditions, the Commission dealt with many complex matters in its effort to ensure that there was no discrimination between the transportation embedded within the pipelines' bundled, city-gate, firm sales services and their open access firm transportation services.

Unbundling the sales and transportation components of the pipeline's city-gate, firm sales service changes the regulatory focus, but does not change the policy direction in which the Commission has been going. Before this order, the primary focus was on whether a pipeline's firm transportation service was comparable in quality to the firm transportation embedded within the bundled, city-gate, firm sales service.[112] After this

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110. 18 CFR 284.8(b) and 284.9(b).

111. 18 CFR 284.8(c) and 284.9(c).

112. *E.g.*, Tejas *supra*, at 1004 ("Without having first assessed the comparability of Texas Eastern's unbundled transportation and storage services, therefore, the Commission could not rationally conclude that the LDCs could take advantage of any alternative sources of gas."); United Gas Pipe Line Co., 55 FERC ¶ 61,330 at p. 61,974 (1991) ("United must specifically demonstrate that its transportation services and storage services available to firm transportation customers are comparable to the transportation and storage in its bundled service offered at market-based rates.").

order, the focus no longer will be on comparing the quality of two different pipeline services. Rather, the focus will be on ensuring that pipeline transportation of all gas supplies is performed on an equal basis under reasonable transportation terms and conditions that enable buyers to use open access transportation to maximize the benefits of a competitive wellhead natural gas market. To ensure equality of transportation service between gas sold by pipelines or their affiliates and gas sold by other gas sellers, the Commission's focus, after unbundling, must be on the quality of transportation service itself.

The Commission recognizes the need to analyze operational conditions in light of the pipeline's need to effectively manage its transportation system and its obligation to perform the new "no-notice" transportation service.[113] But the Commission must ensure that the operational terms and conditions devised to ensure effective system management do not give a competitive advantage to unbundled pipeline and pipeline affiliate sales. It is vital to ensure that gas purchasers have a viable, meaningful alternative to pipeline sales under a market-based pricing mechanism.

B. Transportation Equality and Other Principles

The Commission is amending Part 284 to require an open-access pipeline that offers firm and interruptible transportation services to provide those transportation services on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere. This requirement, embodied in new

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113. Various operational conditions which a pipeline might develop to manage its system are discussed in VII.D below.

Sections 284.8(b)(2) and 284.9(b)(2), will ensure that a pipeline, through a tariff provision or otherwise, does not give its own sales or the sales of an affiliate a preference over sales by other gas sellers in matters relating to Part 284 transportation. This equality principle will ensure that a pipeline cannot impose unreasonable restrictions on a shipper's ability to be served by other gas sellers. Any such restrictions would render transportation of gas sold by the pipeline or an affiliate superior in quality to transportation of gas of other merchants. Such a quality preference would result in undue discrimination under NGA sections 4 and 5 and is prohibited by the equality principle. As discussed above, after unbundling the focus must shift to ensure that the pipeline transports all gas supplies on an equal basis, not simply that the pipeline provides transportation of comparable quality for gas sold by other sellers with which it competes.

While a few commenters request the Commission to set forth uniform terms and conditions of service in the Commission's regulations,[114] the Commission concludes that such industry-wide specificity is not desirable in light of the differing configurations of pipeline systems and the differing needs of pipeline customers. Although the Commission will not develop generic, industry-wide, terms and conditions, the Commission will require that the terms and conditions that are developed must be applied in a non-discriminatory manner, must not give the pipeline or its marketing affiliate a competitive advantage, must not be unduly restrictive, and must be fair to all parties.

However, the Commission concludes that it should

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114. Fuel Managers Association, Appalachian Energy Group, Independent Petroleum Association of America, and American Paper Institute.

codify two other general principles in the regulations. The first is that nothing in a pipeline's tariff can inhibit the development of market centers or hubs. This appears in new Sections 284.8(b)(5) and 284.9(b)(5). While the Commission will not mandate market centers or hubs, it will prohibit tariff provisions that prevent their development.

The second general principle, embodied in Sections 284.8(b)(3) and (4) and 284.9(b)(3) and (4), is that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations.[115]

The precise nature of the information should be developed in the restructuring proceedings established by this order. At a minimum, the Commission will require the pipeline to timely inform all interested persons about the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, and whether the capacity is available from the pipeline directly or through capacity releasing.

To effect this requirement, those sections require all pipelines to use electronic bulletin boards. Since electronic bulletin boards have become standard industry-wide practice, the Commission has designed a rule that builds upon their use and sees no new burden in this requirement. Electronic bulletin boards in particular will be required to comply with the new capacity releasing requirement, discussed *infra*.

Pipelines must not provide preferential access to any users of the electronic bulletin board. They must permit users to

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115. See *infra* on capacity reallocations.

download files from the board, so their contents can be reviewed in detail without tying up access to the board. Pipelines must also keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records, which should be archived and reasonably accessible. Pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information. Information on the most recent entries should appear ahead of older information. In addition, electronic bulletin boards must be "user-friendly." The Commission urges pipelines to use software that allows extremely large files to be split into small parts for ease of use. Furthermore, the Commission urges pipelines to utilize software with on-line help, a search function that permits users to locate all information concerning a specific transaction, and menus that permit users to access separately each record in the transportation log, notices of available capacity, and standards of conduct information. The Commission may revisit these minimum general standards as needs warrant.

The Commission reiterates that, to ensure equality of service, pipelines must include all operating terms, conditions, and rules in their tariffs with the maximum amount of specificity possible. The Commission will focus more closely on compliance with this rule, codified in Sections 284.8(c) and 284.9(c), after unbundling because it is essential to an efficient open access transportation service that the pipelines impose only legitimate and reasonable operational conditions of which all shippers have had advance notice.

The Commission in Section 284.14 is requiring pipelines to have tariff provisions governing, at least, the following transportation matters. First, the pipelines must set forth in their

tariffs their methods for allocating aggregate receipt point capacity, individual receipt point capacity, mainline segment capacity, storage capacity, and delivery point capacity. Second, as discussed below, the pipelines must set forth in their tariffs provisions governing shipper flexibility in changing receipt and delivery points. Third, the pipelines must set forth in their tariffs their provisions concerning supply and capacity curtailments,[116] the scheduling of gas injections into the mainline and into storage, the scheduling of gas deliveries from storage and from the mainline, the setting and charging of penalties, balancing rights, and the instantaneous receipt and delivery of gas. Fourth, the pipelines must set forth in their tariffs their provisions under which they will provide the "no-notice" transportation service required by this rule. The Commission will further discuss the pipeline's "no-notice" transportation service below.

C. Capacity Reallocation

After reviewing the comments and reply comments, the Commission concludes that it is in the public interest for pipeline shippers to have the ability to reallocate unwanted pipeline capacity on a variety of bases to others seeking firm capacity. The only question is the best way to accomplish this on an industry-wide basis. The Commission concludes that this requires the adjustment of previously authorized capacity brokering and other capacity assignment (upstream capacity assignment and releasing) programs for two reasons. First, while the Commission has required that capacity be brokered or allocated on a nondiscriminatory basis,[117] the Commission no longer believes that it can adequately monitor capacity brokering

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116. See *infra*.

117. *E.g.*, Texas Eastern Transmission Corp., 48 FERC ¶ 61,248 at

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under existing certificates to ensure that all allocations are nondiscriminatory. Simply put, there are too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering as it now exists. Second, the Commission believes that the two new generic allocation of capacity programs it is adopting make the necessary adjustments to eliminate the potential for firm capacity holders to unduly discriminate in their assignment of capacity, and facilitate the development of the secondary transportation market.

The Commission, therefore, will not approve new individually authorized capacity brokering and other capacity assignment programs and is contemporaneously amending, by a separate order, the terms and conditions of existing capacity brokering and other capacity assignment certificates to conform to the capacity allocation regulations adopted by this rule. This is necessary to ensure that after the effective date of this rule all capacity reallocations are undertaken on the same basis on all pipelines. This will prevent any pipeline or firm shipper from achieving an undue advantage, or incurring an undue disadvantage, compared to firm shippers on other pipelines, from the working of the particular pipeline's capacity brokering program. Hence, the Commission is taking this action, in the above-noted order, to modify the terms of existing capacity brokering and other capacity assignment programs under NGA Section 5, as well as under the Commission's reserved right in those orders to modify a program, to ensure, as here, that they

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p.61,869-70 (1989), *clarified*, 48 FERC ¶ 61,378 (1989), *order on reh'g*, 51 FERC ¶ 61,170 (1990), *order on reh'g*, 52 FERC ¶ 61,273 (1990).

continue to be required by the public convenience and necessity.[118]

The Commission's treatment of "buy/sell" arrangements being considered in *El Paso Natural Gas Co., et al.*, Docket No. CP88-433-002, *et al.*, is related to the capacity brokering issue. Under those arrangements, an LDC will purchase gas in the production area from an end user or a merchant designated by an end user. The LDC will ship the gas on its own firm capacity and sell the gas to the end user at the retail delivery point. The Commission will not address buy/sell issues here but will do so in the *El Paso* docket. As explained in that order, under this rule, buy/sell arrangements should not be necessary because, under the capacity releasing requirement, firm capacity holders will be able to release unwanted firm capacity to persons seeking firm capacity. However, existing buy/sell deals can continue if the firm capacity holder does not give up its capacity in the restructuring proceeding as discussed below.[119] Similarly, buy/sell deals executed between the date of this order and the date

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118. *E.g.*, Texas Eastern Transmission Corp., 48 FERC ¶ 61,248 at p. 61,876 (1989).

119. In the NOPR, the Commission requested comment on "whether termination of capacity brokering will have a negative impact on independent power producers or qualifying facilities who may be receiving gas service for electric generating purposes through, so-called, 'buy/sell' arrangements." If so, the Commission asked whether it should "provide some form of grandfathering of existing transactions as part of the transitional phase contemplated under the Final Rule?" IV FERC Stats. & Regs. ¶ 32,480 at p. 32,545 (1991). The Commission believes that the steps taken in the final rule should avoid having a negative impact on IPPS or QFs using gas. To the extent this is not the case, interested persons should inform the Commission on rehearing of this rule.

the pipeline's capacity releasing mechanism goes into effect can continue if the firm capacity holder does not give up its capacity in the restructuring proceeding as discussed below. After a pipeline's capacity releasing mechanism goes into effect, no new buy/sell deals may be executed after that date and thereafter *all* allocations of interstate pipeline capacity must be done under the capacity releasing mechanism. When the pipeline's capacity releasing mechanism goes into effect, it must post on its electronic bulletin board for a reasonable period the price, terms and conditions, and names of the parties to all buy/sell deals existing on that date. All firm capacity holders who have executed buy/sell deals prior to that date must provide such information to the pipeline for posting on the electronic bulletin board. This posting is to make those arrangements public and not to allow other persons to make a better offer.

1. Upstream Pipeline Capacity

As discussed above, the Commission is requiring pipelines to unbundle the sales and transportation components of their bundled, city-gate, firm sales services to remedy the pipelines' undue advantage as merchants of gas over other merchants. As stated, one reason for the pipelines' advantage is that, as bundled merchants, they had access to more gas suppliers because of capacity held on upstream pipelines that connect with those gas suppliers.

The unbundling of sales and transportation will occur in many instances near the production area. However, in some instances, unbundling of a downstream pipeline's sales and transportation services will occur where it interconnects with an upstream pipeline which provides the downstream pipeline with access to the production areas. The downstream pipeline

will be able to use its transportation capacity on the upstream pipeline to acquire gas to make sales at the interconnection point to its (the downstream pipeline's) sales customers. The downstream pipeline would have an undue competitive advantage over other gas merchants because of the downstream pipeline's access to the capacity on the upstream pipeline. This situation would inhibit the goal of a competitive national market because the downstream gas purchasers would not have access to the production areas and gas merchants reached through the capacity held on the upstream pipeline by the downstream pipeline.

New section 284.242, therefore, provides that an open access upstream pipeline must permit a downstream pipeline to assign its firm transportation capacity (whether Part 284 or individually certificated) on the upstream pipeline on a non-discriminatory basis to the downstream pipeline's firm shippers. This rule also applies to contract storage capacity that the downstream pipeline holds on the upstream pipeline. In addition, the downstream pipeline will be required to assign its upstream firm transportation capacity (whether Part 284 or individually certificated) and its upstream firm contract storage capacity to its firm transportation customers to the extent necessary to provide capacity to those shippers that desire upstream capacity. All section 284.242 reassignments will be permanent. While this reassignment should occur initially in the restructuring proceedings,[120] section 284.242 will continue in effect after the restructuring proceedings to permit further reassignments of

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120. Section 284.242 capacity reassignment must be effectuated in the restructuring proceedings before downstream pipelines release their capacity under new Section 284.243 discussed below.

available upstream capacity held by downstream pipelines[121] to customers of downstream pipelines.

The NOPR proposed "that a downstream pipeline's capacity on an upstream pipeline should be considered as if that capacity were a mainline segment of the downstream pipeline . . . [and that a] downstream shipper's rights to [such] capacity would be determined under the method used by the downstream pipeline to allocate capacity on mainline segments[.]"[122] The Commission concludes that the issue of how to allocate capacity on upstream pipelines to shippers on downstream pipelines should be determined in the restructuring proceedings.

Texas Gas asks the Commission to clarify that the required allocation of capacity will not apply to interruptible capacity or capacity on intrastate pipelines or exchange transactions. The Commission clarifies that the requirement to allocate capacity on upstream pipelines to shippers on downstream pipelines does not apply to interruptible capacity held by downstream pipelines on upstream pipelines, to firm capacity held by downstream pipelines on intrastate pipelines, or to upstream exchange transactions.

Last, downstream pipelines subject to Subparts B or G of Part 284 will not be allowed to give up upstream pipeline capacity in the restructuring proceedings except under new Section 284.242. This exception is necessary to ensure that firm

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121. If the downstream pipeline releases the capacity under new section 284.243, the capacity would be assignable, however, any prior release would remain in force.

122. IV FERC Stats. & Regs. ¶ 32,480 at p. 32,551 (1991).

customers of downstream pipelines have the first opportunity to gain access to capacity, on upstream pipelines, held by the pipeline to which the customers are directly connected. If the customers of downstream pipelines do not want the capacity on upstream pipelines, the downstream pipeline can release its capacity on upstream pipelines through the capacity release provisions of new Section 284.243, discussed in the next section. If the downstream pipeline is unable to shed unwanted upstream capacity through releasing, it can seek to recover costs associated with the "stranded" upstream capacity as a transition cost as discussed, *infra*.

2. Voluntary Reallocation of Firm Transportation Capacity

The upstream pipeline capacity assignment requirement will provide customers of downstream pipelines with capacity needed on upstream pipelines. This will afford those customers with additional flexibility in their choice of gas sellers. However, this type of assignment is only one aspect of an adequate capacity assignment program. The Commission believes that it is necessary to adopt a program that contains several important elements of capacity brokering so that shippers can reallocate unneeded firm capacity on a variety of bases. Capacity reallocation will promote efficient load management by the pipeline and its customers and, therefore, efficient use of pipeline capacity on a firm basis throughout the year. Because more buyers will be able to reach more sellers through firm transportation capacity, capacity reallocation comports with the goal of improving nondiscriminatory, open access transportation to maximize the benefits of the decontrol of natural gas at the wellhead and in the field.

Appendix B

Accordingly, the Commission is adding a new Section 284.243 to *require* all open access pipelines to provide a capacity releasing mechanism through which shippers can voluntarily reallocate all or part of their firm transportation capacity rights to any person who wants to obtain that capacity by contracting with the pipeline. Shippers may reallocate their firm transportation capacity (whether Part 284 capacity or individually certificated capacity) only under Section 284.243.

This capacity releasing mechanism would allow firm capacity holders to permanently or temporarily release some or all of their capacity through the pipeline to be reassigned to persons desiring capacity. The capacity releasing mechanism would afford buyers and sellers of firm capacity with one place to shop to ensure that firm capacity is used as efficiently as possible.

Capacity releasing will operate as follows. The firm capacity holder will inform the pipeline that it wants to release capacity on a permanent or temporary basis, the specific quantity to be released, the period of time, and any other conditions of the release. For example, the releasing customer might state that it will release a specified amount of capacity only so long as the temperature remains above a specified degree. That is, the firm shipper may release firm capacity on an interruptible basis. In addition, the releasing customer can bring to the pipeline for posting a pre-arranged deal for releasing capacity. If no better offer is received,[123] the pipeline *must* contract with the replacement shipper found by the releasing customer. If a

123. The Commission will not define what constitutes a better offer because of the wide variety of potential releasing scenarios. The parties must consider in the restructuring proceedings the issue of what constitutes a better offer.

better offer is forthcoming, the pipeline must give the replacement shipper found by the releasing customer an opportunity to match the better offer. If the replacement shipper matches the better offer, the pipeline must contract with the replacement shipper found by the releasing customer. If the releasing customer's designated replacement shipper does not match the better offer, the pipeline must contract with the person who made the better offer.

The pipeline must immediately post the capacity releasing information on its electronic bulletin board for a reasonable period of time during which applicants for capacity can agree to the releasing customer's terms and conditions.[124] As discussed below, the pipeline may take other action to market any released capacity.

The pipeline will be required to resell that capacity under Part 284 to the applicant meeting the releasing customer's specifications. The replacement shipper must, of course, satisfy all of the pipeline's tariff provisions governing shipper eligibility before it can contract with the pipeline for the capacity. Unless the pipeline otherwise agrees (such as where there is a permanent reallocation of annual capacity), the releasing customer will remain liable on its contract but will receive a credit against its bill for the capacity resold. The pipeline itself should be indifferent to the substitution because its total contract demand will remain unchanged.[125]

Once the replacement shipper enters into a contract with the pipeline, the replacement shipper becomes a shipper like

124. For example, the pipeline should alert shippers in advance of the conditions under which the releasing shipper may recall released capacity.

125. See *infra* on interruptible transportation capacity.

any other shipper and is subject to the pipeline's operational provisions as stated in its tariff. In addition, the replacement shipper as a shipper can also release its capacity through the pipeline's capacity releasing program. The pipeline's tariff must have provisions that clearly delineate the rights and obligations of such secondary releasing shippers and those of the primary releasing shipper.

The NOPR would have allowed the pipeline to sell its own uncommitted capacity prior to reselling that of a releasing customer. The new rule requires the pipeline to post its available capacity and terms and conditions on its electronic bulletin board. Potential purchasers of capacity will then be able to choose from among the pipeline and the releasers the service that best suits their needs.

The Commission will permit the pipelines and their customers, and other interested participants, to determine the details of a pipeline's capacity releasing program in the individual restructuring proceedings. For example, the NOPR proposed a seven day open season for applicants to agree to the releasing customer's terms. However, the Commission is not mandating a particular time period for an open season to avoid inhibiting needed flexibility. The participants in the restructuring proceedings may determine what is a reasonable period and may, for example, decide that different periods are needed for different types of released capacity. In addition, the participants should determine the pipeline's compensation for the capacity releasing program. This recompense would, of course, consist of a reasonable administrative fee to cover the pipeline's out-of-pocket expenses in connection with establishing and operating the capacity releasing program.[126]

126. *See* Inquiry Into Alleged Anticompetitive Practices Related to (Cont'd)

Moreover, as a further incentive to effectuate capacity releases, the Commission will permit the pipeline to be compensated when it actively markets released capacity.[127] The participants in the restructuring proceedings must determine the appropriate amount of the pipeline's recompense (*e.g.*, a sharing of proceeds) when it takes affirmative action to market the released capacity, beyond posting the information on the bulletin board, and finds a replacement shipper. The releasing shipper will receive a net credit against its reservation fee for the proceeds of the resale minus the pipeline's recompense. The participants should determine what actions merit compensation. Even though the pipelines are required to post the releasing shipper's offer to release capacity, this recompense will give the pipelines a financial incentive to promote efficient capacity reallocations beyond simply posting capacity availability and to benefit releasing shippers via the credit to their bills. Of course, the pipeline will not be compensated if it does not find the replacement shipper, such as where the releasing shipper had a pre-arranged deal as discussed above, or where someone accepts a posted offer without the pipeline finding that new shipper. It is only appropriate for the pipeline to receive compensation when it makes an extra effort to market the released capacity, for example, when it combines two or more packages of released capacity into one, more attractive package. The administrative fee would apply regardless of whether a replacement shipper takes the released capacity since it is

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Marketing Affiliates of Interstate Pipelines, Order No. 497-A, 54 FR 52781 (Dec. 12, 1989), FERC Stats. & Regs. [Regulations Preambles] ¶ 30,868 at p. 31,602 (1989).

127. *E.g.*, Initial Comments of Michigan Consolidated Gas Company.

designed to recover the pipeline's out-of-pocket expenses in administering the capacity releasing program.

The pipeline and the participants must devise in the restructuring proceeding methods for dealing with the circumstance where more than one applicant meets the releasing shipper's price and other specifications or where an applicant makes a counter offer.

The main difference between capacity brokering as it now exists and the new capacity releasing program is that, under capacity brokering, the brokering customer could enter into and execute its own deals without involving the pipeline. Under capacity releasing, all offers *must* be put on the pipeline's electronic bulletin board and contracting is done directly with the pipeline. Nonetheless, the releasing shipper may search for someone to take its capacity both before and after the capacity is put on the electronic bulletin board. However, as stated, a capacity releasing deal cannot be consummated until after it is posted.

The main objection by commenters[128] is that pipelines will have no incentive to effect the releasing of capacity. However, the rule requires the pipeline to establish and operate a capacity releasing program. The pipeline must transfer released firm capacity to willing buyers of that capacity. Because the program will be operated in accordance with the pipeline's open-access transportation tariff, the pipeline may not refuse to provide the requested service if the shipper meets the pipeline's applicable

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128. *E.g.*, Department of Energy, Public Service Commission of the State of New York, Public Utilities Commission of the State of California, United Distribution Companies, and Northern Indiana Public Service Company.

tariff conditions. In addition, as stated above, the Commission is permitting pipelines to market released capacity and to be compensated if they take affirmative action to market the released capacity and find a replacement shipper, beyond posting the information on the bulletin board. Hence, the Commission concludes that pipelines will not act to inhibit capacity releasing.

Of course, the pipeline must continue to sell all its available firm or interruptible capacity. The pipeline must do this by putting the terms and conditions on the electronic bulletin board. It is up to customers to decide if they want the pipeline's uncommitted firm capacity, the released capacity or interruptible capacity.[129] In addition, any change in the level of the pipeline's interruptible volumes due to the releasing program will be accounted for in the pipeline's next rate case when projecting interruptible volumes.

The Commission's adoption of capacity releasing for all pipelines overrules all orders issued subsequent to Order No. 436 to the extent they prohibited capacity assignment.[130]

The regulations require the pipeline to allocate released capacity to the person offering the highest rate not over the maximum tariff rate the pipeline can charge to the releasing shipper. This means that the persons seeking to obtain the released capacity can offer up to the pipeline's filed maximum rate for the service received by the releasing shipper. For

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129. For example, a customer might want annual interruptible capacity rather than firm capacity on a limited basis.

130. *E.g.*, El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,065-66 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987) and Texas Eastern Transmission Corp. 37 FERC ¶ 61,260 at p. 61,684 (1986).

example, if a releasing shipper wants to release firm capacity from the Gulf of Mexico to New York City, the maximum rate would be the pipeline's maximum rate for service from the Gulf of Mexico to New York. That is the maximum rate even if a replacement shipper only wants the releasing shipper's capacity to move gas for a shorter haul (*e.g.*, from the Gulf of Mexico to Atlanta, Georgia).

In addition, the Commission is issuing, to the extent necessary, in the new regulations, a limited blanket certificate of public convenience and necessity under NGA Section 7 to all shippers holding firm capacity rights on pipelines to allow those shippers to release their capacity pursuant to the new capacity releasing program. The purpose of this certificate is limited to allowing those shippers to release capacity to the pipeline as described above. This certificate does not authorize shippers to broker or assign or release capacity as under prior certificates. Rather, new Section 284.243 permits the Commission to ensure that all releases are on a nondiscriminatory basis pursuant to new Section 284.243. Moreover, this will make it clear that the Commission has sufficient jurisdiction to take appropriate enforcement action if capacity is not released on a nondiscriminatory basis. As stated above, the pipeline must contract with, and bill, the replacement shipper.

Last, as stated above, the Commission is amending existing capacity brokering and other capacity assignment programs to conform to the capacity allocation regulations adopted by this rule. Capacity brokering or other assignment arrangements in effect on the effective date of a pipeline's capacity releasing program under new Section 284.243 of the Commission's regulations can continue, provided the broker or assignor does

not give up its capacity in the restructuring proceeding as discussed *infra.* In addition, on the effective date of the pipeline's capacity releasing program, the pipeline must contract with the holder of the brokered or assigned capacity as it would with a replacement shipper at the same price and terms and conditions of the contract between the broker or assignor and the holder of the brokered or assigned capacity. The pipeline must immediately post on its electronic bulletin board for a reasonable period the price, terms and conditions of, and names of the parties to, all such arrangements. This posting is to make those arrangements public and not for allowing other persons to make a better offer.

D. "No-Notice" Transportation Service

As discussed above, the Commission is adding Section 284.8 (a)(4) to its regulations to require pipelines to provide a "no-notice" firm transportation service if they are providing a "no-notice" bundled, city-gate, firm sales service on the effective date of this rule. The Commission expects the pipelines and all interested participants to craft in the restructuring proceedings the operating conditions needed to ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties. This "no-notice" service will enable pipeline customers to continue to receive unnominated volumes to meet unexpected requirements caused, for example, by unexpected changes in temperature. Thus, pipeline customers will be able to receive varying volumes of gas to meet their fluctuating needs during a twenty-four hour period. So, for example, constant rate of flow requirements would not apply to prohibit delivery on demand throughout the

day up to a customer's daily firm entitlement under this service. The pipeline, however, could charge reasonable imbalance penalties, for example, monthly imbalance penalties.

The pipelines must include in their tariffs filed as part of their restructuring filings, and maintain in their tariff after implementation of their restructuring proposal, all operating conditions germane to the provision of a "no-notice" firm transportation service. In addition to knowing those operational conditions, it is important for firm shippers to be aware of the component costs attributable to the "no-notice" transportation service. Only then will pipeline customers be able to make an informed choice about, for example, whether to elect "no-notice" transportation or the pipeline's other open-access, firm transportation service. The pipeline's customers need to know the differences between various services and the costs associated with those differences. Hence, the pipelines must, in the restructuring proceedings, indicate how they derived their "no-notice" and other firm transportation rates. This requires the pipelines to prepare workpapers detailing, among other things, the discrete elements of the "no-notice" transportation service rates, such as the cost of any system storage or imbalance services included within a rate. Furthermore, the pipelines must separately identify those cost components in their rate schedules filed as part of their *pro forma* tariff sheets in their restructuring filings and in future tariff filings. The Commission's aim is for pipeline customers to be able to rationally choose from a menu of pipeline services. The pipeline customers may elect "no-notice" transportation or decide to purchase other open access transportation or other distinct services, such as contract storage or, if offered, an imbalance management service.

It is important to note that this required new "no-notice"

transportation service differs from an "agency" service. The "no-notice" transportation service is a service where the pipeline customer can receive its gas on demand as discussed above. That gas may be purchased from the pipeline or from any other gas seller. The "agency" service is a service where the gas purchaser gives an agent (either the pipeline in its role as gas seller, or another gas supplier) the right to act on its behalf to arrange for pipeline services to deliver the gas. The "agency" service does not ensure "no-notice" service by the pipeline as does the new "no-notice" transportation service to be provided in addition to traditional open-access, firm transportation service. Rather, the "agency" service is a service where the gas purchaser gives an agent the right to act on its behalf in fulfilling its obligations with respect to the pipeline services elected by the gas purchaser. For example, the gas purchaser could authorize an agent to nominate its injections into the pipeline under the pipeline's traditional open-access firm transportation service or to be responsible for responding to operational flow orders to inject gas into the pipeline under the "no-notice" transportation service. However, an agent, such as a marketer, could guarantee a "no-notice" service but, unless the gas is shipped under the pipeline's "no-notice" transportation service, the agent, and not the pipeline, would be responsible for providing the "no-notice" service.

The Commission believes that all pipelines, with appropriate operational conditions, can provide a "no-notice" firm transportation service. This is because the Commission envisions the pipeline managing its unbundled system in a similar manner to its management of its bundled system, except that the place where title to gas transfers will be upstream. Indeed, at the January 22, 1992 technical conference, the pipeline industry representatives indicated that the pipelines

could perform a "no-notice" firm transportation service provided the pipelines retained adequate control of the use of their facilities.[131]

The Commission will not impose or forbid any particular operational conditions at this time. The pipelines and interested participants need the flexibility to explore all aspects of how the pipelines can provide this service in light of the individual configurations of the pipeline systems. Of course, the operational conditions must be devised and implemented on a non-discriminatory basis for all shippers. Simply put, the Commission will not allow any operationally related tariff provision to undermine the quality of unbundled services the pipeline will be required to provide or to give a competitive advantage to the pipeline as a seller or to its marketing affiliate.

The Commission is requiring the pipelines to provide a "no-notice" transportation service as part of its remedy in connection with concluding that the pipelines' bundled, city-gate, firm sales service contravenes NGA Section 5. However, some commenters contend that the Commission's action under NGA Section 5 violates NGA Section 7 because the Commission lacks the authority to revoke, suspend, or adversely modify an issued and accepted certificate.[132]

NGA Section 5 expressly authorizes the Commission to find that any "rate, charge, or classification" or "any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential,"

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131. Technical Conference Tr. 36-38.

132. *E.g.*, PEC Pipeline Group, Associated Gas Distributors, and Baltimore Gas and Electric Company.

and requires the Commission to determine and fix the "just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." The courts have rejected contentions that Commission action under NGA Section 5 is an unlawful revocation or modification of a certificate of public convenience and necessity under NGA Section 7.[133] As a court noted in an analogous situation to that presented here:

> Section 7, which vests in the Commission control over the conditions under which gas may initially be dedicated to public use, does not guarantee that the initial terms of that service will never change. [134]

Of course, "the LDC's entitlement and the pipeline's obligation [have] a legal existence independent of the contract and persist until the Commission issues formal approval of abandonment."[135] Here, the Commission is altering existing bundled sales contracts but is retaining both the LDC's entitlement and the pipeline's service obligation with respect to firm sales, if the LDC and the pipeline agree upon the price for

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133. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n.9 (D.C. Cir. 1985), *citing*, Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 389 (1959) *cert. denied*, 476 U.S. 1114 (1986); Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 746 (5th Cir. 1987); *cert. denied*, 484 U.S. 1005 (1988).

134. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n. 9 (D.C. Cir. 1985).

135. Associated Gas Distributors v. FERC, 824 F.2d 981, 1013 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

gas, and the firm transportation of gas to the city-gate under no-notice transportation service. Conversely, in the absence of an agreement pursuant to the procedures established by this rule, a pipeline's sales service obligation will cease as of the effective date of the tariff sheets filed in compliance with this rule. See discussion, *infra,* in Section IX. The Commission is changing one contract under one certificate for firm sales and embedded transportation into two contracts and two blanket certificates for firm sales and firm transportation. The existing bundled, city-gate service will be supplanted as of the effective date of the tariff sheets filed to comply with this rule. The terms under which the pipelines sell and transport gas are changed. The pipelines' certificates for individual service are, in essence, merged into or subsumed within the pipelines' blanket certificates. Thus, depending on the outcome of the negotiations, any new pipeline sales service obligation will be defined by the terms of the new contractual relationship entered into as a result of the restructuring proceeding. The pipelines' service obligation under the blanket sales certificates and contractual arrangements for unbundled sales are discussed below in Section IX.A, *infra.*

The Commission is giving pipeline customers as part of its remedial action, the right to reduce their unbundled firm sales entitlements in whole or in part as a transition to the market-based gas pricing regime. This will enable the pipeline's firm sales customers to freely negotiate the quantity and price of supplies purchased from the pipeline or other gas suppliers. Those customers will, therefore, be able to take advantage of all opportunities for long-term sales contracts in a competitive market. However, this remedial action does not revoke the pipelines' authority to sell gas. It merely means that the pipelines must compete to retain their business. Last, while "the Commission has plenary authority to limit or to proscribe

contractual arrangements that contravene the relevant public interests,"[136] the Commission emphasizes that a purpose of this rule is to create a regulatory environment whereby gas purchasers and gas sellers can structure their relationships as much as possible by private commercial contracts after the initial transition.

The Commission's analysis of the comments yields two interrelated operational concerns about unbundling and the "no-notice" firm transportation service. The first concern is with keeping the pipeline operational at the pressures required to provide an efficient and reliable transportation service. The second concern is that the pipeline have adequate supplies to deliver on demand. For example, CNG Transmission Corporation expressed concern about losing throughput capacity because of the impact of unbundling on deliveries through displacement.[137] Because the pipeline is operating as a transporter, its ability to effectively manage its system will depend in part on its shippers injecting gas into the mainline (packing the line) and into storage at the right place and time. While the pipeline and its shippers (or their suppliers or agents) may be able to achieve what is needed through communication, cooperation, coordination, and compromise, it may be necessary for the pipeline to retain compulsory powers where it dictates to shippers where and when to act by, for example, operational flow orders. All shippers

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136. Permian Basin Area Rates, 390 U.S. 747, 784 (1968).

137. Initial comments at 20. CNG states that "[d]isplacement occurs whenever gas supplies are recovered at one point on the system for redelivery at another point without a physical flow of that amount of gas along a continuous path between the two points." *Id.* n. 15. For example, CNG is concerned about its ability to ensure reliability with its current storage in the absence of its bundled sales services.

must recognize that the action or nonaction by a single shipper may affect a pipeline's ability to serve all other shippers.

Several additional matters deserve discussion. First, the Commission recognizes that the pipeline must be able to control the operation of the system facilities, such as operation of the compressors and the performance of maintenance. The pipeline may need to enter into agreements with gas suppliers where they balance injections of their shippers and provide predetermined allocation agreements. The pipeline may have to direct shippers to inject gas at particular supply inputs at particular times to keep the line appropriately packed.[138] The pipeline may have to retain *some* storage capacity or have the right to borrow gas from contract storage, or both, to keep the system in balance and to provide this "no-notice" service. [139] The pipeline may have to impose reasonable limitations on the use of storage, including conditions of injection and withdrawal, and may have to designate shippers to particular storage facilities. The pipeline and its shippers need to fashion reasonable, yet effective, methods such as penalties to deter shipper behavior inimical to the welfare of the system and other

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138. For example, at the January 22 technical conference, Arkla Energy Resources emphasized that on web-like systems, the pipeline needs to retain operational control to maintain the bidirectional flow necessary in order to maintain its peak capacity. Technical Conference Tr. 71-73.

139. As a general matter, gas in storage can be analogized to money in a bank. The customer injecting gas into storage is acting like a depositor putting money into a bank. The customer, as a "depositor", may withdraw its gas from the pipeline when it wants. (Of course, the customer's right to withdraw gas from storage is subject to operational constraints.) But the pipeline, just as a bank, may use the "deposited" gas to serve another customer in the meantime.

shippers. The pipeline and its shippers and interested participants may develop reasonable mechanisms to permit the borrowing of gas of one shipper by another shipper so that the pipeline can make deliveries on demand. For example, an interruptible transportation customer with gas in the system may have to allow the gas to be delivered to an LDC to meet its needs when the temperature drops unexpectedly. Once again, the Commission will require the pipeline to devise and implement all operational provisions on a nondiscriminatory basis for all shippers, without diluting the quality of unbundled services that must be offered or creating an advantage to the pipeline as seller or to its marketing affiliate.

The discussion above indicates some of the complex matters that need to be addressed by the participants in the restructuring proceedings. The Commission expects all interested parties to participate in tailoring the appropriate operational features of the pipeline's tariff. However, the Commission recognizes that those provisions may vary from pipeline to pipeline. Moreover, each provision will be scrutinized by the Commission in the compliance filing to ensure that the proposal does not, in any way, undermine the quality of transportation principle set forth above.

The requirement that a pipeline provide "no-notice" transportation service will enable a customer to receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices. Hence, the customer will have the "best of both worlds" — reliable service and competitively priced gas. The following scenario depicts how this would happen.

Appendix B

Upon unbundling, the pipeline's former bundled, city-gate, firm sales customer will be entitled to purchase gas from the pipeline or from another gas supplier and to ship its gas under the new "no-notice" firm transportation service. The customer can also appoint its gas seller, whether it is the pipeline or another gas supplier, to act as its agent in dealing with the pipeline. The agent would be responsible for making all arrangements with the pipeline necessary to deliver the gas to the customer. For example, since it will be up to the customer to ensure that its supplies are capable of physical delivery, the customer or its agent would have to inject gas into the mainline and into its contract storage in conformance with the pipeline's tariff. The pipeline will then be obligated to deliver the customer's gas up to its daily contract entitlement, without penalty, even if this is above the scheduled amount. Thus, the customer's ability to just "turn on the valve," in layman's parlance, would be the same as its current ability under bundled service. This will allow the customer to meet the demand of its system as it has historically done, for example, when the weather suddenly turned cold.

Of course, the pipeline could include in its rates for the "no-notice" transportation service the costs associated with performing this service. For example, it could include the costs of managing imbalances through the use of contract gas in storage. The pipeline could also offer different daily imbalance management options based on a customer's desired tolerance above expected scheduled quantities and allowed tolerances.

The Commission concludes by reminding the industry that it is in the nation's and the industry's interest for them to arrive at legitimate and effective operational conditions which keep gas flowing and deliverable when and where needed and at the same time do not unreasonably inhibit the meeting of gas

purchasers and gas sellers in a competitive market place. Again, the Commission will scrutinize all proposed operationally-related tariff provisions to ensure that they are devised and implemented on a nondiscriminatory basis for all shippers.

E. Storage

As discussed above, the Commission is requiring pipelines to unbundle the sales and transportation components of their bundled, city-gate, firm sales services to remedy the pipelines' unfair advantage as merchants of gas over other merchants. As stated, a reason for the pipelines' advantage is that, as bundled merchants, they have superior access to storage facilities. This is because, at present, an open access pipeline must make system storage available to firm shippers only on a nondiscriminatory basis to assure open access firm transportation service.[140] The Commission has not required open access pipelines to make storage available on an open access contract basis so that shippers may store their own gas.[141]

The pipelines' superior rights with respect to access and control of storage provide them with several advantages over other gas merchants with no access to storage for their gas. First,

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140. Order No. 436, *supra* n.2, at p. 31,507. System storage includes facilities owned and used by the pipeline to store its own gas for operational reasons such as for balancing or for use in lieu of transportation capacity.

141. Some open access pipelines have applied for blanket certificates to provide firm and interruptible open access storage services. *E.g.*, Texas Eastern Transmission Corp., 53 FERC ¶ 61,424 (1990); Northwest Pipeline Corp., 50 FERC ¶ 61,341 (1990) and ANR Pipeline Co., 46 FERC ¶ 61,339 (1989), *reh'g and clarification granted in part and denied in part*, 49 FERC ¶ 61,046 (1989).

the pipelines can use storage to implement seasonal supply management where they purchase gas during offpeak periods. This enables the pipelines to cut gas costs by buying gas when it is less costly during offpeak periods. Second, the pipeline can use storage as a supplement to transmission capacity. This occurs when mainline transmission capacity is less than the pipeline's firm obligations, with the difference delivered out of downstream storage close to the pipeline's market areas. Last, pipelines can use storage to maintain a constant flow of gas by taking supplies from, or diverting gas to, storage. This enables them to manage their system in response to rapidly changing customer demands for gas. The above-described uses of storage give the pipelines an unfair advantage over other gas sellers because non-pipeline shippers do not have the flexibility to provide fully a sales service which meets gas purchasers' peak needs.

The Commission's unbundling of pipeline sales and transportation services means that pipelines with downstream storage will need it *only* to fulfill their obligations with respect to system management (load balancing) and "no-notice" transportation. Because storage is now defined as transportation, under Section 284.1(a), which must be unbundled from sales, the pipeline itself may not retain, or hold, any storage capacity downstream of the place where it unbundles in connection with the providing of any of its own sales services. Hence, the pipelines with downstream storage should have storage available to sell to transportation customers on an open access, nondiscriminatory, contract basis. This will enable open access transportation customers to buy gas and store it for future use. This will enable all shippers to more effectively manage their gas supply and procurement programs.

In addition, shipper access to upstream storage is an

important factor in securing equality for all gas suppliers. For example, this storage is valuable to gas purchasers that want to buy gas off peak at cheaper prices and store it for later use. Preventing access to upstream storage gives the pipelines, as sellers, an undue competitive advantage over other gas merchants and conflicts with the goal of open access to maximize the benefits of competition by requiring all gas supplies to be treated and transported on equal terms.

The Commission is amending Part 284 to require an interstate pipeline to offer access to its storage facilities on a firm and interruptible open access contract basis as part of its open access transportation. This is accomplished by amending Section 284.1(a) of the Commission's regulations to define transportation as including storage. As amended, Section 284.1(a) would read: " 'Transportation' includes storage, exchange, backhaul, displacement or other methods of transportation." Storage, therefore, would be included within the nondiscriminatory access and other requirements of Part 284 for interstate pipelines.[142] Intrastate pipelines would be permitted, but not required, to offer open-access, contract storage under Subpart C of Part 284 of the Commission's regulations. The Commission is also making minor conforming changes to the existing reporting requirements contained in Part 284. Pipelines providing blanket open-access storage services under Part 284 will be required to submit reports to the Commission after the end of each injection and withdrawal season, as is currently required of pipelines holding blanket storage certificates. However, the Commission will not require pipelines to file duplicative self-implementing transaction reports.

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142. *E.g.*, storage rates would be designed pursuant to Part 284 as amended by this order. See also n.141, *supra* for examples of previously certificated open-access storage services.

Appendix B

Pipelines would have to provide access to storage on a firm and interruptible basis for all shipper gas without regard to the seller in a manner that is not unduly discriminatory. The pipeline would be required to offer the open access storage on a basis that is unbundled and not in any way tied or linked to the storage customer's purchase of any particular type of sales service. However, the pipeline may offer both transportation and storage services as part of the service to perform its "no-notice" transportation service required *supra*, but the pipeline must also make storage available on a stand-alone basis. Of course, a shipper purchasing open access contract storage would be responsible for arranging to put its own gas in its firm storage space so that it can be withdrawn when needed.

Commenters raise concerns about the allocation of storage capacity, the pipelines' needs to retain storage capacity for system management, the rights of current holders of contract storage capacity, and whether converting customers under the new regulations should have priority for storage capacity.[143]

The Commission will not impose a generic allocation method for storage capacity. The only requirement imposed in the regulation is that storage capacity must be allocated on an even, nondiscriminatory basis among all shippers without regard to the seller of the gas. For example, the pipeline may hold an open season for initial allocation of storage capacity. Or, storage can be allocated on a pro-rata basis. This should be addressed in each restructuring proceeding. With respect to storage capacity *upstream* of the place of unbundling, the pipeline will be able

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143. *E.g.*, Citizens Gas and Coke Utility, Gas Company of New Mexico, Long Island Lightning Company, New England Gas Distributors, Peoples Natural Gas Company, Washington Gas Light Company, and INGAA.

to continue to retain some of that capacity for its own use as a seller. The allocation of this capacity between the pipeline, for use to make sales, and others, of course, must be done on a non-discriminatory basis and the costs associated with the upstream storage capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream storage capacity (*e.g.*, injection and withdrawal requirements).

Any allocation of storage capacity, however, must take into account pipeline capacity needs for load balancing and system management and the need to reserve some level of storage capacity for the pipeline or for shippers in connection with the pipeline's "no-notice" transportation service. The reservation of storage capacity for these transportation services is different from the pipeline's reservation of storage capacity to make sales. The reservation of storage capacity for transportation functions should be addressed in the restructuring proceedings.

All current holders of contract storage capacity will retain that capacity under current contractual provisions and are not subject to the pregranted abandonment provisions discussed, *infra*. However, as stated above, firm storage capacity held by downstream pipelines on upstream pipelines must be made available to the downstream pipeline's firm shippers under new Section 284.242. Moreover, the downstream pipelines, like all holders of firm storage capacity, can release their upstream storage capacity under Section 284.243.

If the pipeline has storage capacity remaining after it has sold contract storage and retained any system storage needed for system management and load balancing purposes to perform

its "no-notice" transportation service, or to make sales upstream of the unbundling point, the pipeline can seek to recover costs associated with the "stranded" storage capacity as a transition cost, as discussed, *infra.*

Associated Gas Distributors argues that "the final rule should expressly provide that interruptible storage capacity should *not* be made available when that capacity is already held by another shipper."[144] The Commission concludes that pipelines should not limit the availability of interruptible storage unless it is shown in a restructuring proceeding that a particular limitation is operationally warranted on a particular pipeline system.

The NOPR proposed to amend Section 284.1(a) only with respect to interstate pipelines. Houston Pipe Line Company asks that the final rule be clarified to make clear that intrastate pipelines, while not required to provide open access storage service, are nevertheless permitted (or are not denied the opportunity to offer) NGPA Section 311(a)(2) storage services. The Commission has clarified this by amending Section 284.1(a) so that it applies to both interstate and intrastate pipelines.

F. Market Centers and Pooling Areas

1. Market Centers

The Commission is adopting this rule in order to facilitate the meeting of gas purchasers and gas sellers in a national gas market.[145] Market centers may, in certain areas, create additional

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144. Initial Comments at 21 (emphasis in original).

145. *See* the discussion of market centers in Importance of Market

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meeting places for gas purchasers and gas sellers. These inter-pipeline market centers would allow gas from production areas attached to different pipelines to meet where the pipelines intersect to create a market for gas purchasers from different market areas. The Commission believes that market centers should develop naturally and, therefore, will not mandate market centers. However, as stated above, the Commission is requiring in new Sections 284.8(b)(5) and 284.9(b)(5) that there must be nothing in a pipeline's tariff that inhibits the development of market centers.

In addition, as discussed below, the Commission is amending its Part 284 regulations to require pipelines to permit shippers to receive gas into the system and to deliver gas from the system anywhere receipt and deliveries are possible. This should facilitate both the development of market centers and the use of capacity releasing.

2. Pooling Areas

The Commission also believes that the meeting of gas purchasers and gas sellers can be facilitated by the creation of production area pooling areas on individual pipelines. Production area pooling areas may facilitate the aggregation of supplies by all merchants. The pooling areas may either be places where title passes from the gas merchant to the shipper or they may be places where aggregation and balancing and penalties are determined ("paper" pooling areas). The Commission will not mandate pooling areas, but will not permit actions that inhibit their development.

(Cont'd)
Centers, Office of Economic Policy, FERC (Washington, D.C.), August 21, 1991.

At whatever place unbundling occurs,[146] and whether or not a pipeline establishes pooling areas, the Commission believes that pipelines should consider entering into "operational balancing agreements" with other gas merchants to allow them to balance, in the aggregate, for all of their gas purchasers shipping on the pipeline. The Commission also wants the pipelines and their customers and interested parties to consider in the restructuring proceedings the need for appropriate equipment to accurately monitor and measure injections into the system on a timely basis. It may not be cost-effective on some pipeline systems to install the necessary equipment. In those cases, the pipelines should consider allowing other gas merchants to provide the pipeline with pre-determined allocation plans for the merchant's gas. The pipeline should report on this matter in its restructuring filing.

G. Flexible Receipt and Delivery Points

Section 284.221(g) of the Commission's regulations gives pipelines the authority to permit flexible receipt points for receipts of gas volumes into their systems.[147] In implementing that section, the Commission has required that firm shippers must have flexibility in changing firm receipt points and in using all available receipt points on an interruptible basis.[148] This flexibility includes the right to bump interruptible shippers on reasonable notice.[149]

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146. The point of unbundling should be located as far upstream as possible.

147. 18 CFR 284.221(g).

148. Northwest Pipeline Corp., 46 FERC ¶ 61,106 at p. 61,428 (1989).

149. Williams Natural Gas Co., 56 FERC ¶ 61,281 at p. 62,095 (1991).

Appendix B

Section 284.221(h) of the Commission's regulations, also promulgated by Order No. 436, gives pipelines the authority to permit flexible delivery points for deliveries of gas volumes from their systems.[150] However, the Commission subsequently concluded that, in most cases, flexible delivery points were inconsistent with the Commission's requirement of identification of the recipient of the gas in each transaction.[151] The Commission's concern was that flexible delivery points could lead shippers to broker capacity and thereby abuse the first come, first served principle for allocating mainline capacity. However, in *Columbia Gas Transmission Corp.*, the Commission permitted Columbia to institute flexible delivery points because Columbia's firm sales customers had conjunctive billing rights where the customer could accept delivery at multiple delivery points.[152] Recently, in *Transwestern Pipeline Co.*, the Commission approved a proposal establishing flexible receipt and delivery points on Transwestern's system.[153]

The Commission concludes that it should modify its current policies with respect to flexible receipt and delivery point policies to provide for more flexibility. First, the Commission will require pipelines to give firm shippers flexible delivery points in their distribution areas in the same manner as it gives firm shippers flexible receipt points in the production areas. Firm shippers will have the right to change firm delivery points

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150. 18 CFR 284.221(h).

151. El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,066 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987).

152. 52 FERC ¶ 61,041 at p. 61,193 (1990).

153. 58 FERC ¶ 61,299 (1992).

and to use other delivery points on an interruptible basis without losing their priority for firm service.[154] The allocation of capacity at receipt and delivery points will be determined in the restructuring proceedings and set out in the pipeline's tariff as required by new Section 284.14(b)(1)(v) of the Commission's regulations. Second, the Commission will expand firm shippers' rights to receipt and delivery points to include the right to receive gas from any person at any place on the system and the right to deliver gas to any person at any place on the system on a firm basis with the flexibility to change firm receipt and delivery points and to use all delivery points on an interruptible basis. Of course, receipt and delivery points must be within the firm transportation capacity to which the shipper is entitled, and for which it pays. So, for example, an LDC in a downstream region of the country could arrange to deliver gas to an LDC or an industrial in an upstream region,[155] but conversely an LDC in an upstream region could not arrange for delivery in a downstream region.

The Commission believes that these policies are necessary to promote maximum efficient usage of the pipeline systems. For example, flexible receipt and delivery points are necessary to the continued development of market centers where pipelines interconnect. In addition, both flexible rights to receipt and delivery points and distribution area delivery point flexibility are necessary to achieve a broad and meaningful firm capacity releasing program. The Commission believes that the new firm capacity releasing program can operate in a nondiscriminatory

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154. This refers to existing capacity at the distribution area delivery points.

155. The issue of industrial customers potentially by-passing an LDC is discussed below in the transition cost section.

manner alongside the pipeline's allocation of its own available capacity on the electronic bulletin board as discussed above. The new capacity releasing program and flexible delivery point policy mean that a shipper will not lose its firm capacity by changing firm delivery points in order to permit another entity to ship gas through the releasing shippers' firm capacity. Any Commission orders that indicate that a shipper would lose its right to firm mainline capacity by changing firm delivery points are overruled.[156]

H. Curtailment

The Commission's current curtailment policy is that the NGPA Title IV system of curtailment priorities for certain end users applies to curtailments that result from a shortage of pipeline gas supplies[157] and not to curtailments that result from a shortage of transportation capacity.[158] As the Commission stated in Order No. 436:

> [G]as being transported normally should not be subject to curtailment by the pipeline at all, because it would be the pipeline's system

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156. *E.g.*, El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,066 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987) and Texas Eastern Transmission Corp. 37 FERC ¶ 61,260 at p. 61,684 (1986).

157. 15 U.S.C. 3391-4 (1988); El Paso Natural Gas Co., 54 FERC ¶ 61,316 at p. 61,954 (1991).

158. *E.g.*, Order No. 436, supra n.2, at p. 31,515; Order No. 436-A, *supra* n.2 at pp. 31,652-53; *Cf.*, Sebring Utilities Com'n v. FERC, 591 F.2d 1003 (5th Cir. 1979), *cert. denied*, 444 U.S. 879 (1979).

> supply, not the shippers' gas, that would be curtailed.[159]

Accordingly, when a pipeline's gas supplies are scarce, the pipeline should curtail its sales customers without affecting its transportation customers.

With respect to capacity-related curtailments, the Commission has routinely authorized pipelines to have transportation curtailment plans which differ from their sales curtailment plans, and has specifically approved transportation curtailment plans which are based on *pro rata* allocations of capacity.[160] The Commission has, however, permitted parties to agree to an end-use specific transportation capacity curtailment plan.[161]

The NOPR proposed to continue the existing policies with respect to supply and capacity curtailment.

The commenters raise two similar points. Some would apply

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159. Order No. 436, *supra* n.2, at p. 31,515; Order No. 436-A, *supra* n.2 at pp. 31,652-53.

160. *See* Texas Eastern Transmission Corp., 37 FERC ¶ 61,260 (1986); Southern Natural Gas Co., 41 FERC ¶ 61,218 (1987).

161. Florida Gas Transmission Co., 51 FERC ¶ 61,309 (1990); United Gas Pipe Line Co., 46 FERC ¶ 61,314, *order on reh'g*, 49 FERC ¶ 61,096 (1989). Those cases involved settlements where the parties agreed to the curtailment plan. In United, the Commission did find that the capacity curtailment provision was in compliance with the requirements of Title IV of the NGPA. However, the effect of that order was to approve a specific settlement agreement, and any inference that the NGPA mandates end-use specific curtailment plans is misplaced.

the NGPA Title IV priorities to capacity curtailment.[162] Others argue that Title IV priorities should not apply to supply curtailment in an unbundled environment.[163] Both arguments would result in similar treatment for all gas by either applying the NGPA Title IV priorities in all curtailment circumstances or not applying the priorities in any circumstances. In the alternative, Elizabethtown would require pipeline sales customers to exhaust other sources of gas supply and agree to compensate the LDCs suffering more than pro rata curtailment. The Industrial Group would allow the pipelines' customers to fashion emergency plans in the event of *force majeure* capacity curtailment to prevent LDCs from having to cut-off their customers.

The Commission agrees with the commenters' theory that to put pipeline sales and sales by others on an equal footing requires the equal treatment of all gas for both supply and capacity curtailment purposes. However, as stated in *Transcontinental Gas Pipe Line Corp.*,[164] "[u]ntil Congress changes the [NGPA], the statutory priority [for pipeline sales] must be observed."[165] Thus, Title IV of the NGPA must continue to apply to sales only. Moreover, the Commission does not believe it is appropriate to require high priority customers to exhaust other sources of gas supplies before application of the

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162. *E.g.*, Agricultural Minerals Corporation and the Fertilizer Institute

163. *E.g.*, Elizabethtown Gas Company.

164. 57 FERC ¶ 61,345 (1991).

165. *Id.* at p. 62,117.

NGPA Title IV priorities to pipeline sales.[166] With respect to the comments about compensation among pipeline customers in the event of a supply curtailment under the Title IV priorities,[167] the Commission will not prevent, and indeed encourages, such inter-customer agreements. In addition, it may be possible for sales customers of pipelines to reflect their Title IV priorities in their negotiated pipeline supply charges.

However, with the unbundling of pipeline sales from transportation, the NGPA Title IV priorities will only apply to a narrow category of gas supplies — pipeline sales near the wellhead. After the point of sale, all gas will move through the pipeline as transportation gas and will not be required to be curtailed by the NGPA Title IV categories. Rather, the curtailment of deliveries owing to capacity curtailment must be done on a *pro rata* basis or some other basis developed by the parties in the restructuring proceedings.[168] However, the rules and allocation priorities of transportation capacity curtailment plans must be set forth clearly and specifically in the pipelines' tariffs.

The Commission urges the parties to develop tariff mechanisms that provide flexibility, because at the time a need

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166. *Id.* n.57, where the Commission rejected Elizabethtown's request that gas purchasers seeking NGPA Title IV relief take certain remedial action first.

167. *E.g.*, Elizabethtown Gas Company and the Process Gas Consumers Group, American Iron and Steel Institute, Chemical Manufacturers Association, Georgia Industrial Group, and the Association of Businesses Advocating Tariff Equity (Industrial Groups).

168. See n.160 and 161, *supra*.

for capacity curtailment arises it may not be possible to identify ownership of the gas or to control its flow. Hence, it is expected that gas will continue to flow to those who need it for heating or other important needs without regard to any *pro rata* curtailment plan. Therefore, the participants in the restructuring proceedings should address ways to deal with the emergency shortages due to capacity constraints. For example, a pipeline's transportation customers may be willing to release capacity under the capacity releasing mechanism or to sell gas if need be upon reasonable compensation.[169] In any event, the pipelines must file with the Commission, as part of their tariffs, their supply and capacity (transportation and storage) curtailment plans in sufficient detail to accommodate the interests of all shippers. The Commission retains sufficient authority under this rule to prescribe accounting or allocation procedures if needed in the future.

Whether in connection with capacity curtailment or otherwise, the Commission is concerned about allegations that pipelines have permitted the diversion of a customer's gas (*e.g.*, an industrial) to another customer (an LDC).[170] While some commenters suggested the Commission adopt rules on gas accounting matters,[171] the Commission believes it unwise to mandate particular solutions. However, the Commission will require the parties to the restructuring proceedings to address

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169. For example, see the Industrial Groups' proposal in its response to the Commission's Notice of Technical Conference in Docket No. RM91-11-000.

170. *See* the Staff Summary of December 1989 Curtailment Survey Response, Docket No. TC90-8-000, Nov. 1, 1990.

171. *E.g.*, the IPAA.

the issue of the diverting of gas owned by one shipper to another shipper. The participants should explore the possibility of flow control by the pipeline to prevent customers from taking gas. In addition, participants must address the need for and cost feasibility of accurate and timely measurement equipment so that pipelines know how much gas is in the system, whose gas it is, and who is taking delivery of the gas. Pipelines will be allowed cost recovery for purchasing and installing such equipment in their NGA section 4 rate cases, subject to prudence reviews. As indicated above in connection with capacity curtailment, the participants should also explore the need for authorized diversion where the gas can be diverted in specific circumstances with reasonable compensation.

VIII. RATE DESIGN

A. Introduction

As part of the Commission's actions to improve the competitive structure of the natural gas industry, the Commission will adopt the proposed rule and require a generic change in pipeline transportation rates to eliminate potential competitive distortions in pipeline rate structures. Specifically, the Commission's task is to determine the appropriate level of fixed transportation and storage costs to be recovered through the reservation charge[172] and usage charge in designing pipeline rates.[173] This determination is known as cost classification and

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172. Section 284.8(d) of the Commission's regulations permits pipelines to charge a reservation fee. The Commission will here refer to reservation charge rather than demand charge even when the discussion relates to the firm sales demand charge.

173. The usage charge is also referred to as the commodity charge. (Cont'd)

is one part of the ratemaking process described below.

The Commission engages in five steps in fashioning a pipeline's rates for its jurisdictional customers. The first task is to determine the pipeline's overall cost of service.[174] The second task is to functionalize the pipeline's costs by determining to which of the pipeline's various operations or facilities the costs belong. This step is known as functionalization and mainly turns on the particular characterization of the pipeline's facilities as production area, transmission, or storage facilities. The third task is to categorize the costs assigned to each function as fixed costs (which do not vary with the volume of gas transported) or variable costs, and to classify (*i.e.*, assign) those costs to the reservation and usage charges of the pipeline's rates. This step is known as classification. The fourth task is to apportion the costs classified to the reservation and usage charges among the pipeline's various rate zones and among the pipeline's various classes of jurisdictional services. This step is known as allocation. The fifth task is to design each service's rates for billing purposes by computing unit rates for each service. This step is known as rate design. The entire process is known as ratemaking.

The instant rule will not address functionalization, which is mainly important in determining whether facilities are jurisdictional or nonjurisdictional.[175] The Commission will

(Cont'd)
However, usage is the correct term to use in connection with transportation, rather than sales, rates.

174. The pipeline's cost of service is the total revenues needed to cover the pipeline's operations, including a just and reasonable return on its rate base.

175. *See, e.g.*, Trunkline Gas Co. 58 FERC ¶ 61,240 (1992) and Interstate Natural Gas Pipeline Rate Design, 56 FERC ¶ 61,086 (1991).

continue to functionalize between transportation and gathering based on the modified *Farmland* test.[176] The present focus is on classification as it relates to allocation and to the designing of the actual rates.

B. Background

The Commission uses the cost classification aspect of the ratemaking process to achieve policy goals that are pertinent to current conditions. Because conditions change over time, the Commission's goals change and the weight given to various goals also changes. This balancing of goals is a matter of judgement and is not an exact science.[177]

Frequently, however, the Commission has emphasized one particular goal in its ratemaking. That goal is to design pipeline rates in light of competition. This has involved the shifting of costs from the commodity to the reservation charge to keep pipeline rates competitive. For example, in 1965, the Commission approved rates that put ninety-six percent of a pipeline's fixed costs in its reservation charge to take into account competition from coal.[178] After the curtailment era, in

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176. Farmland Industries, Inc., 23 FERC ¶ 61,063 (1983) and Amerada Hess Corp., *et al.*, 52 FERC ¶ 61,268 (1990).

177. Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945) ("Allocation of costs is not a matter for the slide-rule. It involves judgement on a myriad of facts.")

178. *E.g.*, Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967) (The court affirmed the Commission's deviation from the Seaboard (see *infra*) method by putting 96 percent of fixed costs in the demand charge over the objection of coal associations.).

1983, the Commission first adopted the modified fixed variable (MFV) method in recognition of the annual underutilization of pipeline facilities.[179] MFV also was devised to help pipelines sell gas by moving all fixed costs except for return on equity and related taxes to the reservation charge.[180] In almost all cases, MFV reduced the pipeline's fixed costs included in its commodity charge compared to the fixed costs included in the commodity charge under the previously used *Seaboard*[181] or *United* methods.[182] MFV, therefore, was adopted in pursuit of the goal of competition by lowering pipeline sales commodity charges to enable gas to compete effectively with alternative fuels such as oil.

The Commission again emphasized the need for competitive rates when it adopted Order No. 436.[183] Section 284.7(c) of the

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179. Natural Gas Pipeline Company of America, 25 FERC ¶ 61,176 (1983), *order on reh'g*, 26 FERC ¶ 61,203 (1984), *aff'd in relevant part*, Northern Indiana Public Service Co. v. FERC, 782 F.2d 730 (7th Cir. 1986).

180. Future references to fixed costs are to fixed transmission and storage costs. Storage will be unbundled from transportation and separately charged. However, some storage may be retained by the pipeline for its balancing and system management operations associated with transportation and for its no-notice transportation service.

181. Atlantic Seaboard Corp., 11 FPC 43 (1952) (Fifty percent of fixed costs recovered in the commodity charge).

182. United Gas Pipe Line Co., 50 FPC 1348 (1973), *aff'd sub nom.*, Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176 (D.C. Cir. 1975) (Seventy-five percent of fixed costs recovered in the commodity charge).

183. See n.2, *supra*.

Appendix B

Commission's regulations, promulgated by Order No. 436, sets forth the Commission's rate objectives in designing maximum rates for both peak and offpeak periods. In addition to rationing capacity during peak periods,[184] Section 284.7 states that "rates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput."[185] In addition, Section 284.7(d)(5) authorized pipelines to discount their transportation rates below the maximum rate in order to adjust the price to meet competition from competitive fuels and from other pipelines.[186]

The Rate Design Policy Statement, while emphasizing the possible need to ration capacity, also recognized the importance of maximizing throughput in its discussions of discounted rates and rates for interruptible transportation service. In *Panhandle Eastern Pipe Line Co.*, Opinion No. 369,[187] the Commission refined its approach to the rationing capacity and maximizing throughput goals by retaining MFV for cost allocation purposes because there was no need to ration capacity on Panhandle's system,[188] but adopted the straight fixed variable (SFV) for rate design (billing) purposes because of the need to put all fixed costs in the demand charge to maximize Panhandle's throughput.[189]

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184. "Rates for service during peak periods should ration capacity." 18 CFR 284.7(c)(1).

185. 18 CFR 284.7(c)(2).

186. Order No. 436, *supra* n.2, at pp. 31,543-545.

187. 57 FERC ¶ 61,264 (1991).

188. *Id.* at p. 61,843.

189. *Id.* at p. 61,827-30.

Appendix B

C. Discussion

The Commission has discussed above in detail the evolution of the natural gas industry from a regulated, interstate, sales for resale industry with LDCs purchasing gas at the city gate to a decontrolled gas market with gas sold in the production area and transported to the city-gate under Part 284 open access transportation.[190] The Commission is here adopting regulations to ensure that all gas supplies are moved to market on even terms. The Commission is adopting these regulations in order to promote competition among gas sellers (including the pipelines as merchants) in a now national gas market to ensure consumers access to adequate supplies of clean and abundant gas at reasonable prices. The Commission's task is to analyze cost classification, in light of the goals discussed in this order. The appropriate cost classification method used to allocate costs and design rates should in no way inhibit the creation of a national gas market of efficient gas merchants as envisioned by Congress in enacting the Decontrol Act. Ratemaking, like transportation terms and conditions, should comport with the goal that all gas should be shipped on even terms.[191]

The first question is whether the pipelines' currently effective cost classification methods will inhibit the goal of the development of a competitive, national gas market and,

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190. In 1990, transportation amounted to 79 percent of the total gas delivered for market by pipelines. INGAA November 1991 paper, *supra*, Table A-1.

191. At times, the issue has been framed in the context of competition between Canadian and domestic gas. *See* Opinion No. 357, Iroquois Gas Transmission System, L.P., *et al.*, 53 FERC ¶ 61,194 at pp. 61,712 n.91 (1990) and Tennessee Gas Pipeline Co., 51 FERC ¶ 61,113 (1990) (NIPPS II).

therefore, do not comport with the goals set forth in this order or with Congress' goals in enacting the Decontrol Act. In particular, the inquiry is whether the pipelines' current methods distort the gas purchaser's decision because the transportation usage charges vary in the amount of fixed costs included in each pipeline's transportation usage charge. Because the currently effective cost classification method used by most pipelines is MFV, this order will discuss the instant issue with reference to MFV. However, the following discussion and conclusion about MFV applies equally to other methods that recover fixed costs in the usage charge.

Pipelines have differing amounts of fixed costs in their usage charges because those fixed costs (return on equity and related income taxes) are determined by reference to revenue requirement criteria that differ on each pipeline. The portion of the revenue requirement for the return on equity depends on the size of a pipeline's rate base, the pipeline's ratio of equity to total capital, and the allowed rate of return on equity. Because pipelines have rate bases that vary according to their original costs and how much they have been depreciated, and because pipelines have different capital structures and allowed rates of return on equity, the pipelines have different amounts of fixed costs in their usage charges under MFV.[192] Moreover, MFV could bias the debt-equity ratio because pipelines can increase their debt component to lower their usage charges for competitive reasons.

This situation of differing levels of fixed costs in pipeline usage charges can hinder competition between gas sellers at the wellhead because competition is not based on the seller's costs

192. The more equity a pipeline has in its capital structure, the more return and related taxes will be in the usage charge.

and therefore on their ability to compete directly with each other. Rather, competition for sales customers is influenced by the fixed costs in the pipeline transportation usage charges. For example, producers in different fields that compete for market share via different pipelines will often have their competitive positions in that market affected by the amount of fixed costs in the pipelines' respective transportation usage charges and not by the producers' own costs and efficiencies in producing gas. The MFV cost classification method results in the shipment of gas on uneven, rather than on even, terms and will inhibit the development of a national market which "will yield lower prices and more abundant supplies" by "over time forc[ing] the evolution of a set of lowest-cost producers" as envisioned by Congress in decontrolling the price of gas at the wellhead and in the field.[193] Accordingly, unless the Commission permits otherwise, as described below, the Commission concludes that MFV is not in the public interest, unreasonably hinders competition among gas sellers, and is unjust and unreasonable under NGA Section 5.

The Commission here is addressing cost classification for both cost allocation and rate design (billing) purposes. This means that the Rate Design Policy Statement no longer will be applicable to apportioning costs to the reservation and usage charges. However, the Rate Design Policy Statement still will be applicable to other matters, such as the determination of rates for interruptible transportation, the discounting of rates, and the requirement that rates "reasonably reflect any material variation in the cost of providing the service due to . . . [t]the distance over which the transportation is provided."[194]

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193. H.R. Rep. No. 29, *supra*, at p. 7.

194. 18 CFR 284.7(d)(3).

Specifically, the Commission is amending Section 284.8(d) of the regulations to require pipelines to recover their transportation costs under the straight fixed variable (SFV) method of assigning all fixed costs related to transportation to the reservation charge. The Commission, however, will not rigidly preclude the pipeline, its customers, and interested state commissions, producers, marketers, brokers, end-users, and others from agreeing to an alternative method that deviates from SFV and may be appropriate to that particular pipeline system. If the parties affected by a pipeline's rate design agree to a different method, the Commission will consider giving effect to the parties' agreement. However, to the extent a pipeline's rates deviate from SFV, the Commission will carefully consider the arguments of those parties[195] proposing the deviation as well as the parties opposing the deviation. Thus, while a single party cannot preclude the Commission from considering a deviation from SFV, any party (or parties) advocating something other than SFV carries a heavy burden of persuasion. The language in section 284.8(d) of the regulatory text implements this approach and ensures that the Commission will ultimately resolve this issue.

The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equality principle. Under SFV, all gas merchants would be able to compete in a national market without regard to fixed transportation costs included in the usage charge.[196] This

195. Parties include, among others, pipelines, producers, marketers, brokers, LDCs, state commissions and agencies, and end-users, such as industrials and gas-fired electric generators.

196. Only a small amount of variable costs (such as fuel) would be in

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approach is as essential to the shipment of gas on even terms as is equality in the quality of service with respect to gas transportation. SFV would, therefore, maximize the benefits of wellhead decontrol by increasing the nationwide competition among gas merchants (including pipelines). This should result in head-to-head, gas-on-gas competition where the firm transportation rate structure is not a potentially distorting factor in the competition among merchants for gas purchasers at the wellhead and in the field. This merchant-to-merchant competition should help to achieve Congress' intent in passing the Decontrol Act to "over time force the evolution of a set of lowest-cost producers."[197] This "will yield lower prices and more abundant supplies" and benefit all consumers of gas.[198]

Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant natural gas over alternate fuels such as foreign oil.[199] SFV is the best method for doing that. As

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the firm transportation usage charge. Interruptible transportation rates will continue to be determined on a case-by-case basis under the Rate Design Policy Statement. With unbundling, the role of interruptible transportation should be diminished.

197. H.R. Rep. No. 29, *supra*, at p. 7.

198. *Id.*

199. S.R. Rep. No. 39, *supra*, at p. 2 and H.R. Rep. No. 29, *supra*, at p. 2.

discussed above, using cost classification to design rates to influence the consumption of gas is a traditional regulatory technique of the Commission. For example, the Commission has removed costs from the commodity charge to enable pipelines to meet competition for fuel switching customers from coal.[200] And, indeed, the Commission adopted MFV in the context of competition from oil. The Commission finds it appropriate to use that technique again in the current circumstances.

D. Comments on the NOPR's Proposal

The NOPR proposed to adopt SFV for cost allocation and rate design. A few commenters support the NOPR's proposal to mandate the use of SFV generically.[201] More commenters support SFV as a method to be implemented on a case-by-case basis.[202] A number of LDCs and state commissions oppose SFV.[203] Their objections fall into two categories. They first

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200. See, *e.g.*, the discussion of gas versus coal competition in Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967).

201. *E.g.*, Independent Petroleum Association of Mountain States, Colorado Oil and Gas Association, Independent Petroleum Association of New Mexico and Wyoming Independent Producers Association, Panhandle Eastern Pipeline Group (in most instances), and IPAA (presumption).

202. *E.g.*, Natural Gas Supply Association/Indicated Producers and INGAA. The Department of Energy generally endorses the use of straight fixed variable but asks the Commission to "make it clear other rate designs will be approved on a case-by-case basis." Initial Comments at 3.

203. *E.g.*, Distributors Advocating Regulatory Reform, Public Service Commission of the State of New York, Brooklyn Union Gas Company, Baltimore Gas and Electric Company, and Wisconsin Public Service Commission.

argue that the Commission has not established that MFV is anticompetitive. In that vein, they argue that gas purchasers base their gas purchasing decisions on total costs and not only on incremental costs as assumed by the Commission. They also argue that SFV conflicts with other rate design goals. In that vein, they question the impact of SFV on pipeline incentives to enhance service reliability, maintain or maximize throughput, for example, in pipeline-to-pipeline competition, and control costs and the construction of facilities. In addition, they express concerns about the shifting of costs to low load factor customers and about the possibility that LDCs will be forced to reduce their contract demand levels and their ability to reliably serve their customers.

E. Discussion of Comments

1. Mitigation of Cost Shifts

As stated above, commenters express concerns about the shifting of costs to low load factor customers and about the possibility that LDCs will be forced to reduce their contract demand levels and their ability to reliably serve their customers. The Rate Design Policy Statement recognized the possible need for pragmatic adjustments in the event a particular method leads to undesirable or inequitable results, and required administrative law judges to "consider and articulate the impacts (benefits and detriments) of the various rate design proposals on the participants, on the various segments of the industry, and on classes of customers."[204]

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204. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 at p. 62,054 (1989).

Appendix B

The Commission recognizes that the use of SFV, without any adjustments, could result in cost shifting among customer classes. The Commission will require each pipeline to file the information necessary to determine whether mitigation measures are necessary. Accordingly, each pipeline must include in the compliance filing required by this rule a comparison of the revenue responsibility of each customer class, as they have been historically defined, for the unbundled services under (1) the pipeline's last approved cost classification method for cost allocation and rate design and (2) the SFV cost classification method for cost allocation and rate design. If the comparison shows that adopting SFV for cost allocation and rate design will result in a 10 percent or greater increase in revenue responsibility for any customer class, the Commission will require the pipeline to develop and implement a plan to phase-in any such rate increase over no more than four years. The Commission is establishing a bright-line test here for deciding whether cost shifts caused by the switch to SFV must be mitigated. This test applies only to cost shifts due to the change to SFV. Rate changes attributable to other aspects of this rule are not to be considered in determining whether a cost shift is 10 percent or greater.

The pipeline must include in the compliance filing a plan for phasing-in the cost shifts due to SFV over no more than a four year period. This is a one-time mechanism that will automatically terminate no later than four years after the Commission accepts the pipeline's filing in compliance with the final rule. Potential phase-in methods could include use of a one-part volumetric rate or seasonal contract entitlement levels for small customers, creation of new customer classes based on load factor ranges, or creation of new customer classes on that or another basis in order to continue the use of MFV for cost allocation and SFV for billing.

Appendix B

Unless the Commission allows a pipeline to use a method other than SFV, in requiring this phase-in, the Commission does not intend to delay implementation of SFV. In addition, SFV must be used for billing purposes even if a method of mitigating cost shifts is used, unless the Commission permits a pipeline to use a method other than SFV as its approved method of cost classification. The Commission's objective is to provide a reasonable period in which a pipeline's customers can adjust to the new cost classification methodology. The Commission will not mandate any specific type of phase-in plan or requirement at this time. However, as stated, the phase-in plan *must* be included in the compliance filing required under new section 284.14. Finally, the Commission will not accept any mitigation proposal that hinders mandatory unbundling and the Commission's movement towards the use of SFV.

Some commenters argue that the Commission should permit firm transportation customers to reduce their contract entitlements to service in connection with the adoption of SFV.[205] The Commission concludes that it is appropriate to allow reductions of contract entitlements to firm transportation service where another person is willing to take the capacity. The Commission has provided firm shippers with the ability to shed unwanted capacity to other persons desiring firm capacity via the capacity adjustment procedure of the restructuring proceedings discussed *infra*, and the capacity releasing mechanism, discussed, *supra*. The Commission concludes these mechanisms are adequate especially in light of the phasing-in of increases of 10 percent or greater in the revenue responsibility of an historic customer class as discussed above.

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205. *E.g.*, the Industrial Groups.

Appendix B

2. Pipeline Incentives

The Commission has stated in the past that pipelines need an incentive to keep their costs low through an exposure to risk through the assignment of fixed costs to the usage charge.[206] Under SFV, no fixed costs are assigned to the usage charge. Many commenters focused on this point.

The Commission intends to continue to ensure that construction projects are prudent and, of course, pipeline customers may challenge the prudence of pipeline expenditures in rate proceedings. In addition, with respect to transportation throughput, the pipelines will now have much less influence on the use of their systems because they are transporting gas to, rather than selling gas at, the city gate. Transportation volumes will mainly be a function of the needs of gas purchasers and the prices offered by gas sellers in the production areas. The Commission believes that incentive ratemaking may be a better vehicle than exposure to risk for enhancing pipeline efficiency with respect to transportation costs. The Commission is awaiting comments on the proposed policy statement on incentive ratemaking.[207] The proposed policy statement also specifically requested comments on how that policy proposal relates to the rate design methodology proposed in the NOPR. The Commission also recognized that there is a relationship between the proposed policy statement and any restructuring proceedings

206. *See, e.g.*, Texas Eastern Transmission Corp., 37 FERC ¶ 61,260 at p. 61,700-01 (1986).

207. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, Docket No. PL92-1-000, issued March 13, 1992, 58 FERC 61,287 (1992). Comments are due on or before April 27, 1992.

necessitated as a result of this final rule and stated that, after a review of the comments filed in Docket No. PL92-1-000, the Commission will issue guidance in that docket on how a final policy statement affects these restructuring proceedings. The Commission expects to consider the final policy statement in the near future to accomplish this objective in a timely manner.

Last, the Commission received many helpful comments on the impact of SFV on the analysis of pipeline risk in determining rate of return on equity.[208] However, the Commission will not address this issue here because pipeline risk is a matter for pipeline-specific analysis in light of all risks. SFV is but one aspect of risk analysis. This issue is more appropriately addressed in rate proceedings where the Commission examines all other factors affecting risk and establishes the pipeline's allowed rate of return on equity.

3. Gas Purchase Decisions

Niagara Mohawk Power Corporation argues that the Commission's competitive analysis is incorrect because gas purchasers choose between long-term gas suppliers by estimating the "*total* delivered cost of the gas (including both the supply cost and the transportation demand and commodity charges)".[209] Niagara Mohawk asserts that the gas purchasers will not change gas suppliers based on mere changes in the commodity component (gas cost and transportation commodity charge). The Commission recognizes that gas purchasers enter

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208. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 56 FERC ¶ 61,037 at p. 61,136 (1991) (The Commission imposed a 25 basis point reduction in the approved rate of return on equity to reflect the possibility of lower risk.).

209. Initial comments at 32 (emphasis is original).

into long-term and short-term contracts based on the expected total delivered cost. However, even so, this does not invalidate the Commission's analysis. First, the active and viable spot market indicates that a significant amount of gas is purchased on a short-term as well as on a long-term basis.[210] Many purchasers are now developing portfolios of gas supply contracts that are both short- and long-term.[211] Those gas purchasers must make their decisions by comparing the expected incremental cost of the deals available. Spot market sales should continue to play a role in the gas sales market with the implementation of unbundled transportation because a significant amount of gas now moving on an interruptible basis to gas buyers should move on a firm basis, improving the quality and lowering uncertainty associated with gas transactions. This may even increase the use of spot gas to satisfy both base load and peak needs, since the marginal delivered cost to the buyer should be lower because of the combination of unbundled firm transportation and the use of SFV. Hence, the Commission's analysis is directly applicable to a significant and important segment (spot sales) of the natural gas market.

Second, gas purchasers will not be prevented from continuing an expected total cost analysis in entering into new long-term contracts. And it may be easier to compare potential gas sources because no fixed costs under SFV will vary by the estimated purchase volumes. Removing this uncertainty should promote more efficient gas contracting decisions.

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210. See n.41, *supra*. This is further attested to by the fact that in 1990 pipeline sales gas amounted to 21 percent of pipeline carriage for market and that interruptible transportation amounted to 51 percent of carriage for market. INGAA November 1991 paper, *supra*, Tables A-1 and A-6.

211. *See* Initial Comments of the American Gas Association at Appendix A.

Appendix B

IX. PIPELINE SALES

A. Blanket Sales Certificates

The Commission is requiring all pipelines that provide open access transportation to offer their sales services on an unbundled basis. To this end, the Commission is issuing to pipelines holding a blanket transportation certificate under Subpart G of Part 284 of the Commission's regulations, or performing transportation under Subpart B, a blanket certificate authorizing firm and interruptible sales for resale. All firm and interruptible sales services will be provided as unbundled services under the blanket sales certificate. This form of regulation will enable the pipelines to compete directly with other gas sellers on the same terms at prices determined in a competitive market. The unbundled sales services will be afforded pregranted abandonment (see *infra*).

In addition, existing firm sales entitlements of the pipeline's customers will be converted to unbundled firm transportation rights. The pipeline's existing bundled, city-gate service obligation will be supplanted as of the effective date of the tariff sheets to be filed to comply with this rule. The firm sales customers will have the right to reduce their unbundled firm sales entitlements in whole or in part effective on the effective date of the blanket sales certificate. This will enable the pipeline's firm sales customers to freely negotiate the quantity and price of supplies purchased from the pipeline or other gas suppliers, and thereby take advantage of potential opportunities for long-term sales contracts in the competitive market.

During the restructuring proceedings, the firm sales customers may elect whether to continue their contractual relationship with the pipeline under the new blanket sales

certificate. In making this election the customer can negotiate with the pipeline for the price it will pay for the gas. If the pipeline's price is higher than the price the customer is willing to pay, the customer can elect not to contract with the pipeline and can purchase supplies from another gas seller and the pipeline's sales service obligation ceases. If a customer elects to continue its firm sales service in whole or in part from the pipeline, then the pipeline's service obligation correspondingly continues until the contract terminates, either at the end of its term or by mutual agreement. If the customer elects to terminate its existing sales entitlement in whole or in part, the pipeline's corresponding obligation to serve that customer ceases. If the pipeline and a customer enter into a new contractual arrangement during the restructuring proceeding, that contract will define their relationship under the new blanket sales certificate which becomes effective at the culmination of the restructuring period when the Commission accepts tariff sheets putting the pipeline in full compliance with this rule. Under the new blanket sales certificate, the pipeline's sales obligation will be coextensive with its contractual obligations. When its unbundled sales contract expires, the pipeline is authorized to abandon its sales service.

A transportation only pipeline will not be required to offer and sell gas under the blanket sales certificate. Of course, such a pipeline may elect to offer gas in the future under the blanket sales certificate by filing appropriate tariff sheets.

In addition, the Commission is including standards of conduct and reporting requirements as part of the regulations governing blanket sales certificates for pipeline sales (see *infra*). The tariff sheets implementing the blanket sales certificate must be filed under Section 284.14 of the regulations when the pipeline makes its compliance filing in the restructuring

proceeding. Therefore, the pipeline may not implement sales service under the new blanket sales certificate until the Commission accepts those tariff sheets. The Commission does not intend to accept those tariff sheets until the pipeline is in full compliance with this rule.

To conclude, the Commission believes that the blanket sales certificates will be in the present or future public convenience and necessity because they will permit pipelines to make unbundled sales in a competitive production area market in furtherance of Congress' aims in enacting the Decontrol Act.

B. Pricing

The Commission has concluded above that pipelines that continue to sell gas must offer firm sales services that are unbundled from their transportation services. Hence, pipelines will be offering sales services separated from distinct transportation services. These pipeline sales services will be competing directly with unregulated sales by other sellers.

The NOPR proposed that pipelines would be allowed to adopt a market-based sales pricing mechanism for their unbundled firm sales services.[212] The NOPR's proposal was based on the Commission's intention to conclude that any pipeline sale markets are sufficiently competitive to prevent all pipelines from exercising significant market power.[213] The

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212. A market-based pricing mechanism could include, among others, two-part gas inventory charges and as-billed recovery of producer demand charges.

213. The Commission previously concluded that it has the legal authority to approve market-based, unbundled, sales rates upon such a finding. (Cont'd)

Commission's conclusion was grounded on two points. First, the Commission proposed to establish comparable transportation service by amending Part 284. Second, the Commission proposed to conclude that adequate divertible gas supplies exist in all pipeline sales markets.[214] The Commission is adopting a rule that will allow pipelines to adopt a market-based pricing mechanism upon full compliance with the final rule. Some commenters argued that there may be areas where market-based rates are inappropriate. A contesting party in a particular restructuring proceeding can seek to prove that the particular pipeline's sales market is not sufficiently competitive. If that showing can be made, the Commission will decide the appropriate regulatory method to use in lieu of that adopted by this rule.

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Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991); Transwestern Pipeline Co., 53 FERC ¶ 61,298, at pp. 62,114-15 (1990); Transcontinental Gas Pipe Line Corp., 48 FERC ¶ 61,199, at p. 61,753 (1989); Transwestern Pipeline Co., 43 FERC ¶ 61,240, at p. 61,650-52 (1988), *reh'g granted in part*, 44 FERC ¶ 61,164 (1988), *remanded on other grounds*, Transwestern Pipeline Co. v. FERC, 897 F.2d 570 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 373 (1990). Such market-based rates are consistent with the Commission's obligation to determine just and reasonable rates under the NGA and are consistent with the Decontrol Act. *See* Transwestern Pipeline Co., 53 FERC ¶ 61,298 at pp. 62,114-15 (1990).

214. The Commission has found that a pipeline's sales are made in a sufficiently competitive market when the pipeline provides comparable transportation service with respect to all gas supplies from whomever purchased and when adequate divertible gas supplies exist. *E.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

Appendix B

The Commission's competition conclusion rests on two points. First, the Commission will not approve a restructuring plan for any pipeline unless the Commission concludes that the pipeline will provide transportation services for all gas supplies in compliance with the equality principle adopted and defined by this rule. Second, as discussed below, the Commission is concluding that adequate divertible gas supplies exist in all pipeline markets.

The Commission's conclusion of adequate divertible gas supplies is grounded on Congress' passage of the Decontrol Act. As the Commission has stated:

> That act reflects Congress's finding that the natural gas sales market is competitive. . . . The sale of pipeline gas which is . . . unbundled from any transportation service is now part of that same natural gas market which Congress deregulated, and [the pipeline] is . . . competing directly against the producers and marketers whose gas sales Congress deregulated.[215]

Congress, therefore, has determined that gas sales at the wellhead, or in the field, are sufficiently competitive to justify decontrol of all first sales of gas supplies.[216]

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215. Transwestern Pipeline Co., 53 FERC ¶ 61,298 at p. 62,115 (1990).

216. S. Rep. No. 39, *supra*, at p. 3 ("[P]artial wellhead decontrol under the NGPA has helped to create an environment in which competition, not public utility-type regulation, is the dominant force in determining prices and supplies in the natural gas sales markets[.]").

Appendix B

Congress did not decontrol or deregulate gas pipelines or gas pipeline sales that are not "first sales."[217] However, at the time Congress acted, what existed was the traditional or classic bundled sales environment for pipeline sales, and not the unbundled sales environment instituted by this rule. The Commission believes that the Congressional finding of a competitive wellhead or field market applies to all sellers in that market, and that it is reasonable to infer that Congress believed that the production area market for natural gas is competitive on a national level without regard to the status of a particular gas merchant as first seller or non-first seller.

In addition, the Commission now finds that, except as discussed below, the issue of whether sufficient divertible gas supplies exist should not be part of its analysis to determine whether a pipeline possesses market power over sales. Throughout the country, there is a significant amount of uncommitted supplies available at competitive prices. In many areas, uncommitted supplies exceed the largest amount of gas controlled by any pipeline connected to the areas. Indeed, the Commission's experience in approving gas inventory charges in the past few years demonstrates that uncommitted gas supplies are available throughout North America.[218] This means that (with the existence of firm transportation under this rule) sellers of uncommitted supplies could replace pipeline sales, and that it will not be profitable for a pipeline to attempt to exercise market power over the sale of natural gas.

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217. See discussion of the Decontrol Act, *supra*.

218. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991), and El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

Appendix B

The Commission concludes that, after unbundling, sellers of short-term or long-term firm gas supplies (whether they be pipelines or other sellers) will not have market power over the sale of natural gas. To repeat, there is no doubt, as Congress expressly found and confirmed, that a competitive market exists for gas at the wellhead and in the field.

The Commission is, of course, aware of the possibility noted by several commenters[219] that particular markets may not be sufficiently competitive to support a finding that a particular pipeline lacks significant market power. Therefore, the Commission will permit any party in the restructuring proceeding to prove that adequate divertible supplies do not exist with respect to a particular pipeline. The Commission will consider these arguments in each restructuring proceeding and will examine any contesting party's claim that adequate divertible supplies do not exist. In addition, any party may raise the issue of adequate divertible supplies in proceedings subsequent to the restructuring proceedings.[220]

It is important to note that only Congress can "deregulate." Therefore, the Commission is instituting light-handed regulation, relying upon market forces at the wellhead or in the field to constrain unbundled pipeline sale for resale gas prices within the NGA's "just and reasonable" standard. The Commission will be regulating the pipeline sales in the same manner as it has done for sales for resale by marketers. Moreover, the Commission's conclusion is premised on the implementation in

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219. *E.g.*, New England Distributors, Marathon Oil Company, and Associated Natural Gas Company.

220. El Paso Natural Gas Co., 56 FERC ¶ 61,290 at p. 62,174 (1991) ("[P]arties may file a complaint with the Commission to present evidence of any change in market conditions which may give market power to El Paso.").

the restructuring proceeding of equally good quality firm transportation service for all gas supplies regardless of the seller's identity. Last, the Commission concludes that market-based pricing for unbundled pipeline sales is necessary to permit pipelines to compete for gas sales with their competitors on an equal basis with respect to pricing gas as a commodity, as well as in the transportation of gas on even terms and conditions. However, the Commission reiterates, the pipeline's authority to make market-based sales under the blanket sales certificates granted here will not be effective until the Commission accepts its filing in full compliance with the final restructuring rule.

The Commission rejects commenters'[221] argument that the Commission's light-handed regulation of unbundled pipeline sales does not conform to *Farmers Union Central Exchange, Inc. v. FERC.*[222] In that case, the court determined that a lightened regulatory hand is permissible so long as the regulatory scheme acts as a monitor to see if rates are within the "zone of reasonableness."[223] In this order, the Commission has determined that pipeline prices will be limited by a just and reasonable ceiling which is set by a competitive national gas market.[224] In

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221. *E.g.*, Gas Company of New Mexico and Northern Illinois Gas Company, Peoples Gas Light & Coke Company and North Shore Gas Company.

222. 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 1034 (1984).

223. *See* El Paso Natural Gas Co, 56 FERC ¶ 61,290 at p. 62,174 (1991).

224. *See also* Importance of Market Centers, *supra*, at pp. 11-14 (The staff concluded that each of seven production-area market centers has significant uncommitted supplies and that most, if not all, of those supplies would be expected to be economically divertible to customers of interstate pipelines.).

addition, equal transportation must be provided on all pipelines. Hence, pipelines will have no significant market power as sellers. However, in the event parties prove that adequate divertible supplies do not exist with respect to a particular pipeline, the Commission will engage in more active regulation of that pipeline's sales. The Commission believes that the regulatory scheme under this rule will act as a monitor to ensure that rates are within a "zone of reasonableness."

C. Blanket Interruptible Sales Service

The NOPR proposed that there be no restrictions on pipeline unbundled interruptible sales services under the proposed blanket sales certificate. The rule adopted here requires the pipeline to offer firm and interruptible sales service only on an unbundled basis. In addition, the Commission has concluded that unbundled pipelines do not possess significant market power over sales. In that context, the Commission concludes that there should be no limitations or restrictions on pipeline unbundled interruptible sales services (other than standards of conduct, *see infra*.) The unbundling of pipeline sales services will enable producers, marketers, and pipelines to compete for long-term sales on the same unbundled basis. The Commission finds no reason why pipelines should be prohibited from competing on an even basis with producers or marketers for unbundled interruptible sales which are, in effect, short-term (spot) sales.

As with firm sales, the Commission will permit blanket interruptible sales only on an unbundled basis. As stated above, the interruptible sale of gas on an unbundled basis is necessary as a "barrier to undue discrimination in the offer of sale discounts."[225] This moots the interruptible sales service issues

225. El Paso Natural Gas Co., 50 FERC ¶ 61,363 at p. 62,094 (1990). (Cont'd)

considered during the May 2, 1990 Technical Conference in *Arkla Energy Resources, Inc., et al.*[226] Any blanket certificates for interruptible sales on a bundled or unbundled basis will be merged into or subsumed within the pipelines' blanket sales certificates.

D. Standards of Conduct

Order No. 497[227] adopted standards of conduct and reporting requirements for interstate pipelines with marketing affiliates.[228] In brief, the pipeline is prohibited from preferring its marketing affiliate over unaffiliated shippers with respect to

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(Cont'd)

See also Arkla Energy Resources, Inc., 50 FERC ¶ 61,366 at p. 62,103 (1990) ("In *El Paso*, . . . the Commission precludes pipeline ISS merchant service from having an undue advantage over pipeline transportation service by means of the movement of the point at which title to ISS gas transfers [to mainline receipt points].").

226. 50 FERC ¶ 61,366 (1990). This proceeding will be terminated.

227. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec. 22, 1989), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 8, 1992), 58 FERC ¶ 61,139 (1992).

228. 18 CFR Parts 161 and 250. *See also* Algonquin Gas Transmission Co., *et al.*, 55 FERC ¶ 61,261 (1991) with respect to pipeline compliance with the reporting requirements of § 250.16 of the Commission's regulations.

transportation matters, access to information, and transportation discounts.[229] In addition, pipelines are required to establish and file with the Commission procedures to enable shippers and the Commission to determine how the pipeline is complying with the standards of conduct.

The NOPR proposed to continue Order No. 497's standards of conduct and reporting requirements for interstate pipelines with marketing affiliates and to apply those standards and requirements to the pipeline when it provides unbundled sales services.

The Commission is continuing Order No. 497's standards of conduct and reporting requirements for interstate pipelines with marketing affiliates even though the pipelines will be making sales on an unbundled basis with transportation separately provided.[230] This is because there is no change in the competitive relationship between marketing affiliates and other shippers, and the need to protect nonaffiliated customers from preferences that could be given to affiliated shippers.

The Commission also concludes that Order No. 497's standards of conduct and reporting requirements should apply to the pipeline when it provides unbundled gas sales services. The pipeline as a merchant would be the functional equivalent of a marketing affiliate. Therefore, nonpipeline suppliers and other customers need appropriate protection from undue preferences that could be given to the pipeline as merchant just

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229. 18 CFR 161.3.

230. Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992).

as much as protection is needed from potential preferences that could be given to marketing affiliates. Accordingly, the Commission will include standards of conduct and reporting requirements as part of the regulations with respect to blanket sales certificates for unbundled pipeline sales.

Pipelines offering unbundled blanket sales services will be required to organize their sales and transportation operating employees so that they function to comply with sections 161.3(a), (b), (d), and (l) and to comply with (c), (e), (f), (g), (h), and (i) by considering their sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate. In addition, those pipelines will be required to conduct their business in conformity with the equality requirements of Sections 284.8(b)(2) and 284.9(b)(2) by not giving shippers of gas sold by the pipeline any preference over shippers of gas sold by any other merchant in matters relating to Part 284 transportation. Consistent with General Instruction No. 2 of the Uniform System of Accounts,[231] pipelines must maintain sufficient accounting records to ensure that the cost of providing each unbundled service can be identified and assigned to such service. For any costs in which direct assignment is not possible or practicable, for example general overhead costs, the pipeline may use any reasonable method for allocating such costs among the various services. However, pipelines must clearly identify each type of indirect cost, and provide justification of the indirect cost allocation methods selected.

Moreover, the pipelines would be required to file procedures[232] and to comply with section 250.16 by considering

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231. 18 CFR Part 201, General Instruction No. 2.

232. This requirement would be similar to that of 18 CFR 161.3(j).

their sales operating employees as an operational unit that is the functional equivalent of a marketing affiliate.[233] However, the reporting requirement should not require pipelines to file separate Form 592 reports with the Commission. Where pipelines already file marketing affiliate reports with the Commission they should file just one combined report for transactions involving marketing affiliates and unbundled pipeline sales.[234]

Many pipelines[235] and some other commenters[236] oppose the Commission's application of standards of conduct and reporting requirements to unbundled pipelines. They argue that the requirements are unnecessary because the market will regulate competition and the NGA prohibits undue discrimination, that their competitors are not subject to such requirements so pipelines will be at a competitive disadvantage, and that the requirements will be too burdensome.

The Commission concludes that the standards of conduct and reporting requirements are necessary to ensure that the pipeline does not favor itself as a merchant over other gas suppliers in performing its transportation function. The pipelines

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233. Section 250.16 sets forth reporting requirements.

234. The Commission's Form No. 592 is being modified to accommodate this minor change.

235. *E.g.*, Coastal Companies, Panhandle Eastern Pipeline Group, Tenneco Gas, and Southern Natural Gas Company.

236. *E.g.*, Affiliated Natural Gas Marketers Association, American Gas Association, and Equitable Resources Energy Group.

are not similar to other merchants because the pipelines control the transportation network. This is a sufficient difference to necessitate the requirements adopted here.

Some commenters[237] argued that the requirements should be strengthened. The Commission believes that any change in the requirements should be considered for both pipeline sales and pipeline marketing affiliate sales at the same time. Hence, the commenters' proposals to strengthen the requirements will not be considered here.

Last, the Commission rejects commenters'[238] requests that small pipelines be exempted on a generic basis from the standard of conduct and reporting requirements. Small pipelines have the same potential for favoring their own sales as do larger pipelines. The Commission will, however, as it has in the past, consider individual requests for waiver from the requirements where it finds that the potential for preferences has been otherwise mitigated.[239]

E. Reporting Requirements

The Commission is requiring the pipelines to file annual reports with respect to their sales under the blanket sales

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237. *E.g.*, Producer-Marketer Transportation Group, Appalachian Energy Group, Independent Petroleum Association of Mountain States, and Hadson Gas Systems.

238. *E.g.*, Pacific Interstate Offshore Company and Pacific Offshore Pipeline Company.

239. Northern Border Pipeline Co., *et al.*, 55 FERC ¶ 61,262 (1991).

certificate. Currently, Section 154.1(a) provides that pipelines are not subject to the "reporting requirements of [P]art 154 governing the filing of contracts, service agreements and related information . . . [for] the sale or transportation of natural gas pursuant to [P]art 284." The Commission is making no change in this regulation.[240] However, the Commission is waiving the requirements of Part 154 of its regulations with respect to the filing of the sales prices between the pipeline and each of its sales customers. The Commission believes that the reporting requirement added by this rule satisfies the filing requirements of the NGA when the purchaser is on notice of the rate and the amount of total revenues from each purchaser is eventually filed with the Commission as an average price as required by the reporting requirement.[241] In addition, the Commission believes that this is appropriate here because the pipeline sales rates will be negotiated with the purchasers. This eliminates the need for advance notice of the pipeline's prices because market-based pricing obviates concerns about discrimination among gas purchasers. In addition, this will enable the pipelines to compete on an even basis with their competitors for gas purchasers because those competitors are under no obligation to disclose their prices to the pipeline.[242]

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240. 18 CFR 154.1(a). Final Regulations Clarifying the Filing Obligations for Part 284 Transportation and Sale of Natural Gas, Order No. 516, 54 FR 47758 (Nov. 17, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,864 (1989).

241. City of Piqua v. FERC, 610 F.2d 950 (D.C. Cir. 1979).

242. *See* Transcontinental Gas Pipe Line Co., 55 FERC ¶ 61,446 at p. 62,335-6 (1991).

Appendix B

X. PIPELINE SERVICE OBLIGATIONS (AFTER RESTRUCTURING PROCEEDINGS)

A. Introduction

In *American Gas Association v. FERC (AGA II)*,[243] the United States Court of Appeals for the D.C. Circuit reviewed the Commission's regulations promulgated in Order Nos. 500-H and 500-I, and remanded to the Commission the portion of the Commission's decision which provided for pregranted abandonment for each transportation arrangement authorized under a blanket certificate, including transportation arrangements arising out of a sales customer's exercising its right to convert a purchase arrangement to transportation. The court held that the Commission has authority in appropriate circumstances to permit pregranted abandonment under blanket certificates.[244] The court recognized that the event that triggers the pregranted abandonment may be contract expiration. However, the court directed the Commission to develop a further explanation of the criteria under which pregranted abandonment would be permitted. The court was unpersuaded by the Commission's argument that pregranted abandonment helps ensure that capacity will not be retained by existing customers if it is not needed by them, noting that the primary determinant of whether a customer will hold onto excess capacity rights is the size of the demand charge and the degree to which it is related to peak-period use.[245] The court stated that the Commission

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243. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (AGA II).

244. *See also*, Associated Gas Distributors v. FERC, 824 F.2d 981, 1015 n.17 (D.C. Cir. 1987) (AGD I), *cert. denied*, 485 U.S. 1006 (1988).

245. AGA II, *supra*, 912 F.2d 1496 at 1517.

had not adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation — protection of gas customers from exercise of monopoly power through refusal of service at the end of the contract.[246]

On remand of *AGA II,* in Order No. 500-J, the Commission stayed the operation of the pregranted abandonment regulation at issue there, 18 CFR 284.221(d). The stay applied where a customer converted firm sales service to firm transportation service after February 13, 1991, and the Commission indicated its intention to address the issue of pregranted abandonment of transportation service in the context of the instant rulemaking.[247]

Requests for rehearing of Order No. 500-J were filed by numerous parties.[248] Generally, on rehearing, the local distribution companies and state commissions argued that the Commission should vacate its pregranted abandonment rule *in toto,* for firm contracts that are one year or more in length, or

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246. *Id.*

247. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 500-J, 56 Fed. Reg. 6962 (Feb. 21, 1991); III FERC Stats. & Regs. ¶ 30,915 (1991).

248. Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, Panhandle Eastern Pipe Line Company and Trunkline Gas Company, Texas Eastern Transmission Corporation, jointly by Northern Natural Gas Company, Florida Gas Transmission Company, and Transwestern Pipeline Company (Enron), the City of Willcox, Arizona and Arizona Electric Power Cooperative, the State of Michigan and the Michigan Public Service Commission, Indicated Parties, United Distribution Companies (UDC), Associated Gas Distributors, National Association of Gas Consumers, Pacific Gas and Electric Company and the Public Utilities Commission of the State of California.

should extend the stay to small customers who have already converted from firm sales to firm transportation services. The pipelines mainly argued that the stay should be rescinded or at least be only temporary.

After the decision in *AGA II*, the Supreme Court analyzed the Commission's authority to pregrant abandonment in *Mobil Exploration and Producing Southeast, Inc. v. United Distribution Companies* (*Mobil*).[249] The Court held that the Commission has authority under Section 7(b) of the Natural Gas Act (NGA) to decide the issue of abandonment of service in advance, even before service has begun, and that the Commission may make such a determination generically, covering an entire class of cases.[250] As the Court explained, Section 7(b) does not compel the Commission to make specific findings with regard to every abandonment where the issues involved are general. For the reasons discussed fully below, the Commission finds that the proposal in the final rule is consistent with the requirements of Section 7(b) as interpreted in these decisions.

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249. 111 S. Ct. 615 (1991).

250. Section 7(b) states:

> No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

Appendix B

B. Overview of Final Rule

As part of the effort to foster competition in the natural gas industry, the Commission, in the final rule, is allowing the industry greater flexibility to control transactions through negotiated contracts. Consistent with these steps, it is the Commission's view that a pipeline's service obligation also should be determined, in the first instance, by the contract negotiated by the parties. Thus, the regulations to apply after the initial restructuring required by this rule is complete,[251] generally pregrant abandonment of pipeline service obligations upon the termination of the service contracts, with one exception. During the restructuring proceedings, a pipeline is permitted automatic abandonment of the obligation to transport for a firm shipper, if the firm shipper relinquishes its rights to capacity to a competing bidder rather than agreeing to pay a rate, up to the maximum rate, to match the competing bidder's offer. This one-time only abandonment provision during restructuring proceedings is described fully in section XI.A, *infra*.

In section 284.221(d), which applies after the restructuring period, the final rule authorizes pregranted abandonment of interruptible and short-term firm transportation at the expiration of the contract. The rule defines short-term transportation as transportation under a contract with a term of one year or less. In section 284.285, the rule also authorizes pregranted abandonment for unbundled firm and interruptible gas sales service at the expiration of the contract. Thus, under the rule, a pipeline may cease providing service at the expiration of the contract for these services without first obtaining individual abandonment authority from the Commission under Section 7

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251. Regulations governing the procedures to determine the pipeline service obligation during restructuring are discussed in section XI.A., *infra*.

of the NGA. Similarly, for long-term transportation, the rule permits the parties to determine the pipeline's service obligation through contractual provisions such as roll-over or evergreen clauses. This will be discussed more fully below. Because the definition of transportation is being changed by this rule to include storage, the pregranted abandonment provisions will also apply to storage. However, pregranted abandonment will not apply to existing contract storage because existing contract storage was not authorized under Part 284.

The Commission finds that pregranted abandonment is appropriate for short-term and interruptible transportation because the nature of these services is such that the customers selecting those service options do not rely on continued service at the expiration of the contract. Pregranted abandonment for unbundled sales is appropriate because, as discussed more fully below, a pipeline service obligation is no longer necessary to ensure access to gas supply.

The Commission recognizes that long-term firm transportation (over one year) has characteristics different from the services described above, and, accordingly, the final rule places limitations on pregranted abandonment of long-term firm transportation service. These limitations balance the benefits of greater competition with the shippers' need for continuity of service. First, for long-term firm transportation services, a pipeline and its customers may by contract continue the pipeline's service obligations by extending the term of the contract through inclusion of roll-over or evergreen provisions so that customers have the option to renew or extend the contracts.[252]

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252. "Roll-over" and "evergreen" clauses permit the customer at its (Cont'd)

Appendix B

Even if a contract does not contain an evergreen or roll-over clause, a pipeline may not abandon service to a long-term firm transportation shipper if that customer elects, within a reasonable time, to exercise a right of first refusal by agreeing to match the terms (as to price and length) of another offer to purchase service from the pipeline. Only if the shipper is unwilling to pay up to the maximum rate, and match the duration of the contract of another offer, will the pipeline's service obligation be abandoned at the expiration of the contract. The details of how the right must be exercised must be worked out in the individual restructuring proceedings and specified in the pipelines' tariffs.

This order and the final regulations resolve the issues that were raised in the requests for rehearing of Order No. 500-J, and the requests for rehearing are granted and denied, consistent with this order. This order explains, *infra,* that pregranted abandonment will not apply to conversions that took place during the period that the Order No. 500-J stay was in effect, *i.e.,* from February 13, 1991, to the effective date of the regulations promulgated in this order.

The specifics of the final rule with respect to each type of service, the comments received on the proposed rule, and any changes from the proposed rule are discussed in greater detail below.

(Cont'd)
option to extend the term of the contract. For long-term firm transportation contracts, the pipeline must offer these provisions on a non-discriminatory basis.

Appendix B

C. Interruptible Transportation and Short-Term Firm Transportation Service

Section 284.221(d), as amended by the final rule, incorporates the proposal in the NOPR and authorizes pregranted abandonment for all interruptible and short-term (less than one year) firm transportation. The nature of these services is such that customers selecting these options do not rely on continued service at the expiration of the contract. Interruptible customers choose to pay lower rates for less secure service. Short-term transportation customers choose the flexibility of short-term service rather than the stability of long-term commitments. In *AGA II*, the court noted that there was no claim that pregranted abandonment was inappropriate for interruptible transportation. Thus, there were virtually no challenges to the legal basis for authorizing pregranted abandonment for these services.

D. Unbundled Sales Service

The final rule in section 284.285 authorizes pregranted abandonment for unbundled firm and interruptible pipeline sales. Pipelines may cease service to customers for firm and interruptible unbundled gas sales upon termination of their contract without any further action by the Commission. Thus, with the blanket sales certificate, and pregranted abandonment of the sales obligation at the expiration of the sales contract, pipelines are placed in a position that is more comparable to unregulated sellers with which the pipelines must compete. The new post restructuring service obligation of a pipeline to sell gas on a unbundled basis will be co-extensive with its contractual obligation.

Appendix B

While most commenters, including the LDCs, do not object to pregranted abandonment of unbundled sales service, several have challenged the legal basis for this proposal. Laclede Gas Company (Laclede) and several other commenters[253] argue that pregranted abandonment of unbundled sales service violates Section 7(b) of the NGA. The commenters generally recognize that the Commission can authorize abandonment of services on a generic basis, but argue that that authority is circumscribed by the specific requirements of Section 7(b). Laclede argues that Section 7(b) requires, among other things, that the Commission find on the basis of substantial evidence in the record that the present or future public convenience and necessity allows the abandonment. Midwest Energy opposes the proposal unless the pipeline is required to demonstrate that comparable access to essential transportation, production, and storage exists, and that a workably competitive market for firm gas supply has developed in the relevant geographic market. Similarly, Consolidated Edison argues that in order for the Commission to authorize pregranted abandonment of unbundled sales service, it must first find that sufficient divertible gas supplies currently exist; Consolidated Edison maintains that such a finding is premature.

The Commission disagrees with these arguments. The Commission is authorized to pregrant abandonment upon contract expiration or termination upon a finding that the abandonment is permitted by the present or future public convenience or necessity, pursuant to Section 7(b) of the NGA.[254]

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253. *E.g.*, comments of Midwest Gas and Consolidated Edison Company of New York, Inc.

254. AGA II, *supra*; Mobil, *supra*. See discussion, *supra*.

Appendix B

The Commission here finds that pregranted abandonment of firm and interruptible unbundled gas sales service upon termination or expiration of the sales contract is permitted by the present or future public convenience and necessity because a continuing pipeline service obligation is no longer necessary to ensure LDCs access to gas supply. Moreover, pregranted abandonment will further the goal of placing all natural gas sellers on an even basis.

The Commission has found above that sufficient divertible gas supplies exist nationwide to prevent a pipeline from exercising market power over the supply of gas at the termination of a contract.[255] Thus, individual abandonment proceedings are not needed to protect LDCs from market power over natural gas supplies and assure continued access to supply. With unbundled firm transportation, LDCs will have as many gas supply options as the pipelines. In addition, the final rule requires pipelines that currently make firm city-gate sales to offer a "no-notice" transportation service[256] that, in combination with unbundled sales, can provide reliable deliveries of gas up to the customer's contract demand level during periods of peak demand. Each firm customer will be entitled to continue this transportation service beyond the term of existing long-term contracts, and preclude the pipeline from abandoning such service, by exercising contractual roll-over or evergreen provisions or by exercising a right of first refusal, as described more fully below. Thus, LDCs will be able to secure new supplies of gas in a competitive market, either from the pipeline

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255. Any allegation that this conclusion does not apply to a particular pipeline will be addressed on a case-by-case basis in the restructuring proceedings. See discussion, *supra*.

256. Described *supra* at section VII.D.

or other sellers, without being subject to pipeline market power over such supply, and will be assured of the means of transporting that gas when it is needed.

Moreover, the rule does not limit the current ability of pipelines and their sales customers to negotiate unbundled sales contracts containing "roll-over" and "evergreen" clauses, such that customers have the option of renewing or extending gas supply commitments from the pipeline. Thus, the application of the pregranted abandonment for unbundled sales service would be deferred as to contracts containing such clauses as long as the purchaser continues to renew or extend the contract because the contractual relationship has not terminated.[257] The inclusion of such clauses in agreements for unbundled sales is a matter of contract, to be determined by the negotiations of the parties, and not by Commission rule or policy.

In addition, pregranted abandonment of future unbundled sales service will further the goals of this rule by permitting pipelines to provide sales service on a more competitive basis with other gas suppliers, who have already been relieved of service obligations that extend beyond the terms of their gas supply contracts by virtue of the NGPA, the Decontrol Act, and previously established Commission policies. In 1978, Section 601(a)(1)(A) of the NGPA removed the Commission's NGA jurisdiction over first sales of new gas that was not dedicated to interstate commerce before the NGPA's enactment, and thus obviated the necessity for producers to secure certificates of public convenience and necessity to sell such gas for resale in

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257. Existing contracts with evergreen clauses will also preclude the availability of pregranted abandonment as long as the customer elects to continue receiving sales service under the contract.

interstate commerce, or to secure abandonment authority to discontinue such sales. Subsequent Commission regulations promulgated under Order No. 451 (Ceiling Prices: Old Gas Pricing Structure) and Order No. 490 (Abandonment of Sales and Purchases under Expired, Terminated, or Modified Contracts) provide producers with blanket sales certificates with pregranted abandonment for pre-NGPA gas. Marketers have been granted blanket sales certificates with pregranted abandonment.[258] As of January 1, 1993, all first sales of gas will be removed from the Commission's NGA jurisdiction under the Decontrol Act. With the unbundling of transportation required by this rule, it is now appropriate to allow pipelines to compete with these other sellers on an analogous basis.

E. Long-Term Firm Transportation

Once again, the following discussion pertains to the application of the regulations after the initial restructuring proceedings are completed. Section 284.221(d), as amended by this rule, places limits on pregranted abandonment of long-term firm transportation service.[259] The criteria established for pregranted abandonment for long-term transportation contracts of long-term firm transportation will foster competition and economic efficiency, and streamline the administrative process, while protecting the legitimate needs of many customers for continued service. The parties may choose to defer application of pregranted abandonment by including evergreen or roll-over clauses in their service contracts. Thus, in the first instance, the parties will decide whether their service obligations under the

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258. *E.g.*, TXG Gas Marketing Co., 55 FERC ¶ 61,063 (1991).

259. There are different procedures that apply during the restructuring proceedings that are discussed *infra* at section XI.A.

contract will be subject to pregranted abandonment. If these provisions are not included in the contract, the customer is still assured the right to continued service if it meets competitive bids, as discussed below.

Under the rule, the parties' ability to use an evergreen or roll-over clause to guarantee the firm shipper a continuing discounted rate will depend on the terms of the existing contract. For example, if the existing contract guarantees the shipper the right to extend the term of the contract at a rate that is less than the maximum rate, the terms of the contract will govern. Otherwise, if there is unsatisfied demand for the capacity, the firm shipper must be prepared to pay up to the maximum rate to retain the capacity. If, however, the pipeline has unused capacity, the parties can negotiate a discounted rate.

These limitations on the pregrant of abandonment for long-term transportation reflect the Commission's determination that the current regulation, which provides for unconditional pregranted abandonment,[260] is not appropriate for firm transportation with a duration of more than one year. The key to continuity of service for a customer is the right to transportation capacity, regardless of the source of gas. The final rule provides customers with the ability to ensure the continued availability of transportation capacity. The Commission finds that with these limitations on pregranted abandonment for long-term firm transportation, the rule meets the requirements of the court in *AGA II*.

1. Comments on the NOPR

Several commenters have challenged pregranted abandonment of long-term firm transportation service, alleging

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260. 18 CFR 284.221(d). See discussion, *supra*.

that the process is inconsistent with Section 7(b) of the NGA. Atlanta and Chattanooga argue that permitting abandonment on a generic basis, subject only to an existing customer's right of first refusal is incompatible with Section 7(b) of the NGA as that section has been interpreted by the courts in *Michigan Consolidated Gas Co. v. FPC*[261] and *Transcontinental Gas Pipe Line Corp. v. FPC.*[262] Atlanta and Chattanooga argue that, consistent with these decisions, abandonment may be authorized only after hearing and a finding that the abandonment is permitted by the public convenience and necessity.

However, neither of the cited cases involves the issue of pregranted abandonment and cannot, in light of *AGA II* and *Mobil*, be read to require the Commission to make an individual determination in all abandonment proceedings. To the extent those cases require a comparative analysis of the public interest considerations for the existing service and the new service, that analysis is set forth in this order, *supra*, and is the basis for the Commission's authorization of pregranted abandonment.

Associated Gas Distributors (AGD) and Consolidated Edison state that a regulation establishing criteria necessary for continuation of service would not be inconsistent with Section 7(b), but a regulation that provides a new customer with an opportunity to take capacity away from an existing customer because it offers different terms would undercut the purpose of the statute. The distinction between the Commission's proposed right of first refusal and a "right to continue" service, as proposed by AGD, is semantic, not substantive. In any event, evergreen and roll-over clauses will provide this right to continue service.

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261. 283 F.2d 204 (D.C. Cir. 1960), *cert. denied*, 364 U.S. 913 (1960)

262. 488 F.2d 1325 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974).

2. The Right of First Refusal

a. Rate Requirement

The exercise of the right of first refusal established in the final rule, that will apply after the restructuring proceedings are complete, will be a means of avoiding pregranted abandonment, in the absence of contractual provisions to extend the contract duration. This right of first refusal will enable any long-term firm transportation customer, including formerly bundled city-gate sales customers, to continue receiving that firm service by agreeing to pay up to the maximum rate and matching the length of contract term offered by another customer who wants and values the service. If the pipeline is willing to discount the transportation rate for competitive reasons, the pre-existing customer may retain the capacity by matching the highest rate, up to the maximum, offered by a competing bidder.[263]

Consolidated Edison of New York and Kansas Power & Light asked for clarification on matching competing bids from a downstream customer. The maximum rate that must be matched means the highest rate the pipeline is authorized to charge for the capacity sought. A bidder in a downstream zone may not force an existing customer in an upstream zone to match the higher maximum rate for capacity to the downstream bidder's delivery point. The maximum rate an existing capacity holder must match is the maximum rate the pipeline can charge for

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263. There is also a similar provision that applies during the restructuring proceeding that is discussed, *infra*, at section XI.A. During the restructuring proceedings, the holder of firm capacity has an opportunity to shed unneeded capacity prior to expiration of its contract, if there is a demand for its capacity, thus triggering the automatic abandonment provisions of § 284.14.

delivery to the existing customer's delivery point. The downstream bidder, however, must bid up to the maximum rate for delivery to its delivery point. If each shipper bids the maximum rate for its zone, and the same length for contract duration, then the existing capacity holder retains its capacity.

This procedure allows the rate to play a role in rationing capacity, but caps the rate at a just and reasonable level. The maximum rate contained in the applicable tariff and approved by the Commission will be at a just and reasonable level and not at a level that results in monopoly rents to the pipeline. The pipeline cannot under any circumstances collect a rate that is above a just and reasonable level, but competitive circumstances may result in a lower rate.

The rate regulations for open access transportation require that pipelines establish a maximum rate designed to recover all of the costs (and only such costs) properly allocated to the service to which the rate applies, and a minimum rate based on the average variable costs.[264] The existing customer is entitled to continue long-term transportation service by matching whatever transportation rate (within the maximum and minimum rates) is offered by another party. If there are no competing offers, the existing customer and pipeline establish the rate (within the maximum and minimum) by negotiation. Therefore, an existing holder of capacity is entitled to continue to receive transportation service upon expiration of its long-term contract, but not necessarily at a discount.

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264. 18 CFR 284.7(d)(4) and (5).

b. Contract Term

The second requirement of the right of first refusal upon expiration of a long-term contract is that the existing transportation customer agree to match the longest contract term offered by another customer interested in receiving the service. Thus, if a competing bidder offers to pay the maximum transportation rate for a term of 20 years, the existing customer cannot retain the capacity by agreeing to pay the maximum rate for some shorter term. But if there are no competing offers, the existing customer is entitled to continue the transportation service for whatever term it chooses.[265] Therefore, an existing holder of capacity is entitled to continue to receive transportation service upon expiration of a long-term contract, but not necessarily on a short-term basis, unless there are no other customers bidding on the capacity.

Several LDCs and state agencies argue that the right of first refusal should apply to the price term only, *i.e.*, that the bidder should be required only to bid the highest Commission approved rate.[266] These parties argue that while it may be appropriate to make the LDC pay the highest cost-based rate, it would not be appropriate to require them to match the term for contract duration. Otherwise, these parties assert, bidding wars will result in excessively long contracts, tying up capacity, contrary to the

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265. Although if the extended term is one year or less, it will be subject to the pregranted abandonment authorized for short-term transportation contracts upon expiration of the contract.

266. *E.g.*, Niagara Mohawk Power Corp., Baltimore Gas and Electric Co., Cascade Natural Gas Corp., Long Island Lighting Co., and Minnesota Dept. of Public Service.

goals of the rule.[267] Furthermore, several parties argue that LDCs cannot reasonably be expected to know their requirements beyond 10 years.

Others argue that the maximum term required to be matched should be limited to a specific period, which, when elected, would automatically entitle the existing customer to continued service. Distributors Advocating Regulatory Reform (DARR) suggests a term of three years; Central Illinois Public Service Company suggests a term of ten years; and Consolidated Edison suggests a minimum term of five years.

The Commission will require existing customers to match the length of competing bids for capacity under expired contracts, as well as price, in order to retain the capacity. This proposal strikes the appropriate balance between the needs of customers for continued service and the benefits of competition in establishing the terms of service. In the first instance, the parties have control over the timing of pregranted abandonment as to their contracts and can defer the abandonment of the pipeline's service obligation by including a roll-over or evergreen clause.[268] Absent such a contractual provision, other shippers desiring the service may compete for it. Existing customers may have the greatest need for continuation of firm transportation under their expiring contracts, and continuation of that service to them may be the most efficient use of the capacity. The rule assures them this opportunity. But there must also be an

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267. *E.g.*, comments of Distributors Advocating Regulatory Reform.

268. Pipelines are not required to include rollover or evergreen clauses in transportation contracts, but if they do so, these clauses must be offered on a nondiscriminatory basis for all shippers, consistent with existing Commission policy.

opportunity for other shippers desiring the capacity to submit competing bids, which the existing customer can then match or not. This process affords an efficient, market-sensitive means of comparing the needs of the existing customer to those of competitors for the capacity, and measuring whether or not the public convenience and necessity requires that service should be continued to the existing customer.

While the limitation on price, to a rate that recovers only properly allocated costs, precludes differentiating among customers offering the maximum rate, there need be no such limitation as to length of the contract term. Other things being equal, a pipeline would prefer a longer term contract for service at the maximum rate than a shorter term. Other things being equal, the satisfaction of long-term transportation needs should have priority over the satisfaction of shorter-term needs. Accordingly, the Commission sees no reason to establish some maximum contract term, beyond which existing customers would not have to obligate themselves in order to retain firm capacity. This is particularly true in view of the capacity releasing mechanism adopted in the final rule which establishes a mechanism for the firm shipper to release unused capacity.

c. Mechanics of the Process — Post-Restructuring Proceedings

Many parties have asked the Commission to clarify the mechanics of exercising the right of first refusal that will apply after the initial restructuring proceedings. For example, several ask whether customers have one opportunity to bid or if it is an iterative process.[269] Kansas Power and Light Company suggests

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269. *E.g.*, Interstate Power Co. and New Jersey Natural Gas Co.

that the capacity holder should be able to wait until the bidding process is completed and then decide whether to match the most favorable bid.

At the outset, the right of first refusal is not a new, untested concept in gas regulation. The NGPA provided rights to purchasers of certain gas removed from the Commission's jurisdiction. Section 315 of the NGPA provides for a right of first refusal at the expiration of a contract for the first sale of natural gas to the person who, but for deregulation, would have been entitled to receive the gas. The right of first refusal under the NGPA gives the original purchaser the right to match the terms of a third party offer to purchase the gas at the expiration of the contract. If the original purchaser refused to match the terms of the third party offer, then the seller could sell the gas to the third party under the terms of the offer. Once the gas had been sold to the third party pursuant to the offer, the seller had no further obligation to the original purchaser.

The right of first refusal under this order will work similarly. When the contract is nearing expiration, the pipeline may seek offers from other persons interested in receiving the transportation. As discussed above in connection with capacity releasing, the pipeline is required to post available capacity and terms and conditions on its electronic bulletin board. If several offers are received, the pipeline will select one of the offers as the offer it will accept if the existing customer chooses not to match its terms. The pipeline will then present this offer to the existing customer, which, if it chooses to match the terms of price and duration, will continue to receive the transportation service from the pipeline. If the existing customer elects not to match those terms of the offer, then the pipeline must provide transportation service to the third party under the terms of the

offer. If, in fact, transportation is not provided pursuant to the offer with respect to both rate and term, then the original customer is entitled to continued service at the pre-existing rate.

Offers may present different benefits to the pipeline. For example, a pipeline could receive an offer to purchase transportation for a period of five years at the maximum lawful rate, and a second offer to purchase transportation for ten years at a rate less than the maximum. The Commission is not specifying in this order the appropriate method of determining which is the "best" offer. The parties must consider methods of evaluating offers, such as, for example, calculating net present value, in the restructuring proceedings. The mechanics of the right of first refusal must be developed in the restructuring proceeding and set forth in the tariff including a provision that will implement an appropriate method of determining which is the "best" competing offer.

d. Bona Fide Offers

Other commenters[270] are concerned about the integrity of the right-of-first-refusal process. They fear that pipeline affiliates could artificially bid up the transportation rate. They assert that the standards of conduct applicable to pipelines with marketing affiliates, and the NOPR's proposal to apply those standards to pipelines' marketing divisions, would not prevent this, and state that the pipeline should be required to demonstrate that an offer is *bona fide.*

As discussed above, parties can protect themselves from

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270. *E.g.*, Midwest Energy, Inc. and Distributors Advocating Regulatory Reform.

these concerns through contractual provisions. However, the Commission recognizes that disputes may arise about whether a third-party bid for capacity under an expired contract is *bona fide*. Parties to the restructuring proceedings should address this issue and develop procedures for distinguishing between *bona fide* and spurious offers. For example, it may be appropriate for a third-party bidder to post a bond, or pay a reasonable "down payment" when it tenders its bid.

e. Offers for a Portion of Existing Customer's Capacity

TransCanada Pipeline, Ltd. asks the Commission to clarify that when an existing customer exercises its right of first refusal to retain capacity under an expiring contract the competing bidder must bid for all of the capacity under the existing customer's contract, not just a portion of it. If, for example, an LDC had a contract demand of six million MMBtu's per day under an expiring contract, any competing bidder would have to bid on all of the capacity under the contract to trigger the LDC's obligation to match the offer in order to retain the capacity. If a competing bidder sought anything less than the total capacity under the expiring contract, the existing customer could ignore the offer and retain the capacity.

The Commission clarifies that competing bids must be matched by existing customers, even if they are for less than the total capacity reserved under the existing customer's contract. The policy urged by Transcanada would virtually insulate the very largest holders of transportation capacity from the bidding process. On the other hand, the fact that a competing bidder has bid the maximum rate for a very long term for only a portion of the capacity under an existing customer's contract

does not mean that the existing customer must match that offer for the remaining capacity. The existing customer need only match the competing bid for the amount of capacity to which the bid applies. If, for example, there are no other bids for the remaining capacity, the existing customer would simply proceed to negotiate the terms of a renewed contract for that capacity with the pipeline, without regard to the terms it had to match to retain the capacity for which there was a bid.

f. Converted Sales

As explained above, in *AGA II,* the court remanded the issue of pregranted abandonment of transportation service under section 284.221(d) of the Commission's regulations. On remand, in Order No. 500-J,[271] the Commission stayed the operation of this regulation where a customer converts firm sales service to firm transportation service after February 13, 1991.[272] The result was that these converted transportation arrangements would never be subject to pregranted abandonment and may be abandoned by the pipeline only upon receipt of Commission approval under Section 7(b) of the NGA.

Several commenters ask the Commission to clarify that conversions that have occurred during the effectiveness of the stay of pregranted abandonment under Order No. 500-J will never be subject to pregranted abandonment, nor have to exercise a right of first refusal to avoid pregranted abandonment. These parties note that while the NOPR states that transportation converted from sales during the period the stay is in effect would

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271. III FERC Stats. & Regs. ¶ 30,915 (1991).

272. *Id.* at p. 30,083.

remain subject to traditional section 7(b) abandonment, the text of the proposed regulation does not reflect this.

The Commission clarifies that conversions that took place during the effectiveness of the stay, *i.e.*, from February 13, 1991, to the effective date of the regulations promulgated in this order, will never be subject to pregranted abandonment. The revised section 284.221(d) specifically so provides. The Commission will require the pipelines to notify the Commission of all transportation arrangements that resulted from conversions during this stay in each pipeline proceeding implementing this rule. The stay is terminated on the effective date of this order.

Peoples Natural Gas Company argues that this provision discriminates in favor of conversions that took place during the effectiveness of the stay. However, the Commission finds that no one is aggrieved by this provision because, as explained above, the parties can defer pregranted abandonment by including an evergreen or roll-over clause in the contract. Absent such provisions, customers are protected by the right of first refusal. In sum, the rule contains sufficient safeguards so that customers that convert under these rules can be in essentially the same position as those that converted during the interim period.

XI. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

The Commission recognizes that the natural gas industry cannot get to the new regime required by this rule in an instant. Contracts, and certificate obligations, will have to be renegotiated, revised, and in some cases, terminated. Pipelines will have to design rates to reflect their restructured services

and incorporate the straight fixed variable rate design method. The transition to fully unbundled pipeline services will entail certain costs, and pipelines will need to propose mechanisms for recovery of those costs during the transition period. In this section, the Commission will discuss some of the issues that arise in connection with the transition, and the schedule and procedures to be used for an orderly and expeditious implementation of this rule.

A. Adjustment of Purchase Obligations and Firm Capacity

1. The Need for Adjustments

The restructuring required by this rule will result in significant changes to pipelines' services and rate structures, so that contractual commitments by pipelines and their customers must be subject to reevaluation and possible adjustment in view of those changes. Contracts entered into under significantly different regulatory conditions than those established by this rule, and under market conditions that in many cases were substantially different than today's, cannot be presumed to be just and reasonable under the regulatory structure established by this rule. Thus, pipelines and their customers that entered into long-term sales agreements when there were few if any reliable alternatives for the customers, or long-term firm transportation agreements, will have opportunities to adjust their commitments in light of the new commercial realities established by this rule and current market conditions.

The Commission finds that the continued enforcement of a pipeline sales customer's purchase obligations, agreed to before implementation of unbundling under this rule, is unjust and

unreasonable, and unduly discriminatory. Therefore, during the restructuring proceedings established by this rule, unbundled sales customers will be permitted to reduce or terminate, in whole or in part, their purchase obligations under contracts with their pipeline suppliers. Such contracts were entered into when the pipeline had a virtual monopoly over the provision of reliable "no-notice" sales service, because of the unavailability to other shippers of the storage and load balancing services necessary to provide such service, and the numerous restrictions placed on transportation service for gas sold by nonpipeline merchants. Customers are therefore authorized to reduce or terminate their sales purchase obligations under such contracts as a remedy, to afford them access to the competitive gas market, and the Commission is granting pipelines abandonment authority to reduce or terminate their sales obligations in accordance with their customers' elections.[273]

In addition, with the conversion to unbundled transportation and sales services current pipeline firm sales and transportation customers may decide that they no longer need to retain the same quantity of firm transportation as previously. Most firm capacity holders under existing contracts are obligated to pay the maximum transportation rate. Thus, existing firm capacity holders will need to reassess their future needs for capacity. As a result, the customer may no longer need the same level of

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273. Without the assignment of supply contracts, which must be done without undue discrimination, a customer's reduction in purchase obligations will likely result in the incurrence of costs by the pipeline. The pipeline will have the opportunity to recover these costs, either in the form of reservation fee surcharges on future transportation service, a negotiated "exit fee," or some combination. To avoid these charges or fees, the Commission strongly urges the customers to enter into negotiations to assume supply contracts. See *infra*, under discussion of transition costs and recovery mechanisms.

transportation from a certain pipeline, for example, because of capacity that becomes available on another pipeline. As another example, a current sales customer may decide that after conversion to unbundled firm transportation and unbundled sales it no longer needs, or wants, to maintain firm capacity rights from the beginning to the end of the mainline, but rather, only needs firm rights from a certain pooling point or market center that may be developed during the restructuring proceeding.

During the restructuring proceedings all firm capacity holders must reexamine the amount of firm capacity that they will need, or want, to continue to hold in light of the new services and rates to be developed to comply with this rule. Also, in order for the pipeline to develop the rates and range of services it will offer after restructuring, it will need to know whether and how much capacity its current firm capacity holders will continue to hold. Therefore, all firm capacity holders must participate in the restructuring proceedings and notify the pipeline of the amount of capacity they intend to continue to hold after restructuring.

Capacity that is no longer wanted by the current holders can be reallocated during the restructuring proceedings as follows: All firm capacity holders must notify the pipeline of the amount of capacity they intend to retain after restructuring, at the pipeline's proposed maximum rate or at an existing discounted rate, if no other shipper is prepared to bid for that capacity.[274] Where the pipeline has a queue for firm service, the pipeline must notify the current firm capacity holder if another shipper is prepared to bid more than the current capacity holder

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274. As discussed more fully below, certain shippers by contract are not obligated to pay the pipeline's maximum rate.

pays for that capacity. In that event, if the firm capacity holder is unwilling to pay up to the maximum rate to retain its existing capacity rights, the firm capacity holder must give notice that it wants to reduce or terminate its contractual rights to firm service. If the capacity holder makes that election, the pipeline is granted an automatic abandonment of its service obligation under Section 284.14(e) to the extent of such reduction or termination, so that it can reallocate the capacity to another shipper. This mechanism can be invoked unilaterally by an existing firm capacity holder to relinquish all or a part of its firm capacity *only* if there is a demand for the capacity and another shipper is prepared to bid for that capacity. Where there is no competing bidder for the capacity, the existing customer's rights and obligations under the existing contract are unaffected, since this provision is designed only to ensure an efficient allocation of capacity where there is unsatisfied demand for the capacity. Thus, it provides a limited opportunity for transportation CD reductions.

However, if an existing firm capacity holder wants to relinquish all or part of its existing capacity, but there are no competing bidders, nothing in the final rule precludes the pipeline and the capacity holder from negotiating CD reductions. For example, the pipeline and the shipper may agree to terminate or reduce CD upon the capacity holders' payment of a reasonable exit fee.[275] If this occurs the Commission will give effect to this agreement, including effectuating the parties' deal by granting abandonment of the pipeline's obligation.

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275. An exit fee is reasonable if it provides compensation to the pipeline for all the costs attributable to the departing customer so that the pipeline will not seek to allocate any unrecovered balance of the costs attributable to the departing customer to remaining customers. *See* Northern Natural Gas Company, 59 FERC ¶ 61,003 (1992).

Appendix B

Where there is unsatisfied demand for capacity, a firm capacity holder should not continue to receive service at a discounted rate, if another shipper is prepared to bid more, up to the maximum rate, for that capacity. Unless the pipeline is contractually precluded from charging the maximum rate, when there is unsatisfied demand for capacity, the pipeline must charge the highest price (up to the maximum rate) bid for that capacity. Any other pricing behavior is inefficient and unduly preferential to the shipper receiving the discount. Therefore, while the Commission will not adopt the proposal contained in the NOPR, during the restructuring proceedings, pipelines must reduce or eliminate any discounts up to the maximum rate for firm transportation in such circumstances, unless the pipeline is contractually precluded from charging the maximum rate.[276] The maximum rate, up to which a current firm shipper must be prepared to pay where there is unsatisfied demand for the capacity, is the maximum rate the pipeline is authorized to charge the current firm shipper for delivery to that shipper's existing delivery point. A competing bidder must be prepared to pay up to the maximum rate the pipeline is authorized to charge the competing bidder for delivery to that bidder's proposed delivery point. The current firm shipper only needs to bid up to its maximum rate.

Where the parties have negotiated and included in their contract either a fixed rate or some permanent form of discount, such as ninety percent of the maximum rate, the Commission recognizes the importance of giving effect to each party's

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276. Although the Commission may permit utilities to increase rates above the level agreed to in a fixed rate contract if it finds those rates so low as to adversely affect the public interest, FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956), there is no basis in the record of this proceeding for making generically applicable findings to that effect.

respective contract rights. This is consistent with the general purposes of this rule, to give parties the ability to control their transactions as much as possible through their contracts. Where such contracts exist, the Commission recognizes that it is not unduly preferential for the pipeline to continue to charge the discounted rate.

To facilitate this capacity reallocation process, the Commission has included in this rule a special abandonment provision to permit the reallocation of transportation capacity during the restructuring period. Generally, under Section 284.221(d) the pipeline is permitted to abandon transportation service where a contract expires or is terminated by the parties. However, Order No. 500-J stayed the effect of that provision for certain firm contracts so that the pipeline would have to file individual abandonment requests for transportation service under those contracts. Under new Section 284.14(e), the pipeline is granted automatic abandonment of its transportation obligations to correspond to any election by a current firm capacity holder to relinquish some or all of its existing firm capacity during the restructuring proceeding, as discussed above. This provision will permit the speedy abandonment and reallocation of transportation rights and obligations during the restructuring proceedings where the firm transportation rights were acquired during the period of the Order No. 500-J stay.

The Commission proposed in the NOPR that firm capacity holders could retain long-term transportation capacity under existing contracts only by exercising a right of first refusal during the restructuring proceedings, *i.e.*, by agreeing to match the price (up to the maximum) and most favorable (longest) term offered by any competing bidder. The purpose of this proposal was to require all parties to existing contracts for long-term

transportation service and bundled sales service to re-evaluate their need for firm capacity in view of the new unbundled service options and restructured rates. The Commission has changed these provisions in this rule and has included a mechanism to facilitate the orderly reallocation of capacity as described above.

The NOPR also proposed to permit pipelines' unbundled firm sales customers to reduce or terminate, in whole or in part, their firm sales entitlements (purchase obligations) during the restructuring proceedings. The final rule incorporates that proposal without change. Only the sales customer has the option to reduce or terminate sales service, not the pipeline. A pipeline's obligation to provide sales service continues, to the extent its sales customer elects to continue receiving sales service, for the duration of the existing sales contract. The automatic abandonment of the pipeline's obligation to provide sales service, granted in section 284.14, only applies to the extent the pipeline's sales customers elect to reduce or terminate, in whole or in part, sales service from the pipeline during the restructuring proceeding. After the initial restructuring, the provisions of the new blanket sales certificate will apply.

Parties will have to make decisions concerning their rights to adjust their service under the provisions of this rule in the course of the restructuring process, which will necessarily be iterative. A pipeline will propose a menu of unbundled services after discussions to determine the needs of its customers and other interested parties. The pipeline will need to estimate the extent that customers will use the restructured services and develop *pro forma* rates to recover its cost of service. Customers will review the pipeline's proposed services and rates and estimate their levels of usage. The pipeline may need to revise its proposed rates, and perhaps its menu of services, in response

to the initial indications of demand. Customers (or potential customers) that want additional transportation capacity will submit bids for that capacity at rates within the maximum and minimum rates proposed by the pipeline. As the process nears completion, sales customers will have to elect whether to continue buying gas from the pipeline on an unbundled basis at the same level as under their existing contracts. As described above, all long-term firm capacity holders (including formerly bundled sales customers) must notify the pipeline of the capacity they intend to retain, reduce, or terminate. In the end, gas supply and capacity will be reallocated in accordance with the needs of customers in an unbundled environment, where customers will have a range of choices not previously available.

The Commission expects and requires all parties — pipelines, producers, LDCs, end-users, state commissions, and others — to participate in the restructuring proceedings to reach this objective. Moreover, the Commission will require the discussions taking place during the restructuring proceedings to be conducted in an open and nondiscriminatory manner as to all parties. However, the Commission will permit restructuring discussions to take place outside of the Commission's offices.

2. Discussion of Comments

Many LDCs and industrial customers objected to the proposal to jeopardize their long-term transportation arrangements by requiring them to match competing bids to retain capacity. Some LDCs argue that this procedure will drive up their costs by forcing them to compete with industrial bidders that do not have any public service obligation.[277] Many industrial

277. *See, e.g.*, Citizens Gas and Coke Utility, Interstate Power Company, Panhandle Customer Group, and UGI Corporation.

customers and electricity generators protest the prospect of having to pay higher rates after having structured financial arrangements on the basis of negotiated transportation rates, especially those that have recently negotiated long-term contracts for firm transportation service at discounted rates.[278]

These provisions have been changed in the final rule. However, the Commission's goal is still to effect a more efficient allocation of capacity. Where the demand exceeds available capacity, and another shipper is prepared to bid up to the maximum rate for that capacity, the pipeline must charge the highest rate bid up to the maximum fully allocated, cost-based rate for the capacity. If existing capacity holders have not negotiated fixed discounted rates for that capacity, then they must be prepared to pay up to that rate or release the capacity to other shippers that are willing to pay up to the maximum rate.

As noted above, most LDCs with contracts for bundled sales service are currently paying fully allocated, cost-based rates for the embedded transportation service, which is the equivalent of the maximum rate for open access transportation. For capacity converted under the transitional provision of this rule (18 CFR 284.14), the only question is whether LDCs will have the opportunity to negotiate for a discounted transportation rate in the process of the pipeline's unbundling and restructuring. If there are competing bidders willing to pay the maximum rate for the capacity, the LDCs will not have that opportunity. If there are no competing bidders, or none willing to offer the

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278. *E.g.*, Midland Cogeneration Venture Limited Partnership, New England Power Company, Southern California Edison Company, Thermo Electron Corporation, Agricultural Mineral Corporation, The Fertilizer Institute, Mississippi Chemical Corporation, Process Gas Consumer Group *et al.*, and Reynolds Metals Company.

maximum rate, LDCs can negotiate for a discounted rate. All other shippers with firm transportation capacity at discounted rates will also have to match competing bids, unless they have fixed-rate contracts. If shippers have long-term contracts for firm transportation with fixed-rate provisions that are below the maximum rate, they will not have to pay the maximum rate or match competing bids to retain their capacity. Nor will customers that receive transportation under individual certificates, rather than Part 284 open access blanket certificates, have to match competing bids, because the provisions of this rule do not apply to such service.

The Panhandle Pipeline Group argues that there are no findings or facts to support the proposal to permit sales customers to have the unilateral right to reduce their purchase obligations under their sales contracts, and note that the Commission's attempt to allow such unilateral reductions in Order No. 436 were expressly rebuffed by the court in *AGD I*[279] Pacific Gas Transmission Company urges the Commission to honor all existing firm service agreements between pipelines and their customers, absent a case-specific finding that a particular contract is unduly discriminatory, or otherwise anticompetitive or contrary to the public interest. Natural characterizes the proposal in the NOPR as giving a pipeline's customers the right to abrogate existing firm sales contracts with their pipeline suppliers, which it opposes as one-sided and disruptive. Columbia and Natural argue that if customers have the right to revise their contractual obligations to purchase gas, pipelines should also have the right to reduce or eliminate their obligations to sell gas.

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279. Associated Gas Distributors v. FERC, 824 F.2d 981, 1013-21 (D.C. Cir. 1987), *cert. denied sub nom.*, Interstate Natural Gas Association of America v. FERC, 485 U.S. 1006 (1988).

Columbia states that its primary concern with the NOPR involves the one-sided nature of the contract renegotiation process for sales service. Columbia notes that pursuant to its recent global settlement,[280] Columbia entered into sales agreements with its wholesale customers to provide approximately 360 Bcf of sales service annually through the year 2004. Under the terms of the NOPR, according to Columbia, its sales customers would be able to pick and choose the precise level of sales service they desire, while Columbia would not be given any similar opportunity.

Natural points out that it entered into new contracts effective December 1, 1990, at a time when the essential framework of open access transportation was in place on its system. Natural asserts that the new contracts are for limited terms of not more than five years, and that it has made (or retained) supply commitments with producers based on these sales contracts with its LDCs. According to Natural, the Commission's "wholesale abrogation" approach tests the limits of the Commission's authority, and undermines the confidence of parties in the efficacy of contracts subject to regulation by the Commission. Natural argues that if customers abrogate these contracts pursuant to the final rule, Natural should be guaranteed total recovery of any resulting costs.

The Commission recognizes that the customers of Columbia and Natural may have had more choices than some other customer groups during the recent, post open-access renegotiations of sales contracts. Nevertheless, neither Columbia nor Natural currently offers fully unbundled transportation and storage services of a quality equal to that embedded in their

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280. *See* Columbia Gas Transmission Company, 49 FERC ¶ 61,071 (1989), *reh'g denied*, 51 FERC ¶ 61,194 (1990).

firm sales service. Thus, their customers were still subject during the recent contract negotiations to the pipelines' monopoly over reliable, no-notice delivery service for which the customers' right to adjust purchase obligations is a remedy.

However, the Commission has crafted a rule that balances the interest of the pipelines and their customers by permitting pipelines to abandon firm sales obligations where customers elect to reduce or terminate purchases, and to recover 100 percent of any gas supply costs, as Natural urged, incurred as a result of their sales customers' elections. Knowing that the pipelines will be entitled to 100 percent recovery of the costs of realigning their gas supply contracts (described *infra*), purchasers must exercise considerable prudence in deciding whether to exercise their rights under this rule to reduce or terminate their purchase obligations. This is an area where cooperation between a pipeline and its sales customers can minimize the transition costs. For example, customers can postpone the effective date of their reductions of purchases from the pipeline to correspond to the term of certain of the pipeline's producer supply contracts that would have to be renegotiated, thus giving rise to transition costs, if the customers terminate purchases. However, the customer will be making these decisions in the context of the restructuring proceeding. In order for these choices to be meaningful, the pipeline must put on the table the full range of unbundled services, and the estimated rates for those services, that it expects to offer to comply fully with the final rule. Only then can customers make rational choices and elect the services that meet their needs.

Appendix B

B. Transition Costs and Recovery Mechanisms

1. Summary and Rationale

The Commission recognizes that pipelines will likely incur costs as a result of implementing the requirements of this rule. The issues are how, to what extent, and from whom, should the pipelines recover those costs.

The Commission envisions four types of costs. The first type are the unrecovered gas costs (or credits) remaining in the purchased gas adjustment (PGA) Account No. 191 when a pipeline adopts market-based pricing for its gas sales and terminates its purchased gas adjustment mechanism (the "Account No. 191 balance"). The second type of costs may result from the pipelines realigning their existing gas supply contracts with producers in connection with implementing this rule ("gas supply realignment costs"). A third type are the costs of a pipeline's assets now used to provide bundled sales service, such as gas in storage, and capacity on upstream pipelines, that cannot be directly assigned to customers of the unbundled services ("stranded costs"). A fourth type consists of costs associated with physically implementing the rule (*e.g.*, meters, valves, communications equipment)("new facility costs").

Under market-based rates, the pipeline would no longer recover gas costs through a PGA mechanism, but it may have unrecovered gas costs in Account No. 191 when it discontinues that recovery mechanism. The Commission will permit pipelines to "direct bill" the Account No. 191 balance to their former bundled, firm sales customers, as proposed in the NOPR, whether or not the customers elect to continue as firm sales customers on an unbundled basis after implementation of this

rule. The unrecovered gas costs should not be billed to customers who are not sales customers during the period when liability for the direct bill is established, because the gas purchase costs are not incurred for them and they would not have to pay those costs if the PGA were to continue. Furthermore, customers would have the right to challenge the prudence of the gas purchases reflected in the Account No. 191 balance.[281]

The unrecovered gas costs are not future costs incurred to comply with the rule, but are costs incurred prior to implementation of the rule.[282] The Commission's proposal in the NOPR that the underrecoveries in Account No. 191 would be direct billed put pipeline customers on notice that they would have to pay any such costs accrued after July 31, 1991, the issuance date of the NOPR. The Commission reiterates that pipeline firm sales customers will be responsible for unrecovered gas costs in Account No. 191 accrued prior to implementation of this rule. Customer responsibility for commodity-related Account No. 191 costs may be based on their gas purchases for the twelve months preceding the effective date of service under the pipeline's unbundled sales certificate (granted under § 284.284), and for unrecovered demand charges in Account No. 191, based on contract entitlements on the day preceding that effective date.[283] The pipelines must permit customers to

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281. *See* Transcontinental Gas Pipe Line Corp. 46 FERC ¶ 61,364 at p. 62,147 (1989).

282. The costs are incurred prior to implementation when the gas is taken prior to implementation, even though paid for afterwards. For example, there may have been a billing dispute. *See Id.* at p. 62,147.

283. Pipelines or other parties to the restructuring proceedings may propose other mechanisms if the above described mechanism is inequitable

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pay the direct bill in either a lump sum, over twelve months or over some other reasonable period of time, at the customer's option.[284] Of course, a pipeline must refund any overrecoveries in its Account No. 191 and flow through to its customers any refunds it receives that are attributable to the relevant past period.

The second type of costs, gas supply realignment costs, may result from the pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers in connection with implementing this rule. The Commission will permit pipelines full cost recovery of prudently incurred gas supply realignment costs deemed to be eligible under this rule. To recover those costs, a pipeline will be permitted to use either a negotiated exit fee, or a reservation fee surcharge recoverable from Part 284 firm transportation customers.

Under this rule, a firm entitlement holder has options as to how to react to gas supply realignment costs: it may remain a sales customer of the pipeline; otherwise, it may take an assignment of the pipeline's existing contracts or pay an exit fee/reservation fee surcharge for costs approved by the Commission. To mitigate any transition costs that may arise, the Commission strongly recommends assignment of gas supply contracts. Unless the specific gas supply contracts prohibit assignment, the pipeline would assign those contracts on a non-

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(Cont'd)
— if for example, there are large underrecoveries but very few customers were making purchases during the base period.

284. Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364 at p. 62,147 (1989); Northwest Pipeline Corp., 45 FERC ¶ 61,224 (1988), *reh'g granted in part*, 46 FERC ¶ 61,091 (1989).

discriminatory basis to those who choose to receive assignments.[285]

If there are excess gas supply contracts held by the pipeline after assignment, the pipeline should realign those contracts. Where the pipeline remains in the merchant business, it should realign its portfolio to leave it at a market responsive level, enabling it to compete on a even basis with any other merchant. The Commission, in a Section 4 filing by the pipeline to recover gas supply realignment costs, will perform two levels of review.

The first level will be an eligibility review to determine whether the resulting realignment costs are attributable to events which occurred independently of the final rule, or whether they are attributable to the implementation of the final rule. That proportion of gas supply realignment costs which are determined to be attributable to the final rule will be eligible for 100 percent cost recovery if the Commission finds that the costs were prudently incurred. If the Commission finds that a portion of the gas supply realignment costs are attributable to events that are independent of the final rule, then it will treat such costs accordingly and continue the use of the recovery mechanism developed in Order No. 528. Where the total sum of gas supply realignment costs is partially eligible and partially non-eligible, parties should devise an allocation method which divides the costs among the two recovery mechanisms proportionately.

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285. Although the Commission will not prescribe a certain assignment/allocation mechanism, it expects the parties to adhere to non-discriminatory principles that will result in equal treatment for all potential assignees regardless of whether they are sales customers of the pipeline. The Commission expects assignments to minimize the costs that will be recovered in a reservation fee surcharge to the fullest extent possible.

Appendix B

The second level of review will be for prudence. In any rate filing, all costs are subject to prudence review; the Commission is not proposing a new standard under this rule. The Commission's primary objective in any prudence review of gas supply realignment costs will be to determine that the total amount is as minimal as possible. Elements of this determination should include, but not be limited to, the following: whether the contract terms were reasonable in light of the market conditions existing when the contract was negotiated, renegotiated or terminated, whether the contract realignment costs resulted from vigorous arms-length negotiations, and whether there was a *bona fide* effort on the part of both parties to the contract to arrive at a settlement.

The Commission will permit prudently incurred gas supply realignment costs to be recovered by use of a reservation fee surcharge or an exit fee. A surcharge mechanism will be in addition to a pipeline's reservation charge for firm transportation and storage services, and will thus be recoverable from all Part 284 firm transportation customers. The surcharge will not be applicable to interruptible transportation service or transportation under individual NGA Section 7(c) certificates. Parties may also negotiate for the payment of an exit fee, in lieu of, or in combination with, a reservation fee surcharge. The exit fee could be a cash payment made by a sales customer that reduces or terminates its sales obligation during the restructuring proceeding.

The pipeline and interested parties may negotiate allocation of gas supply realignment costs among the pipeline's various firm services in the restructuring proceedings. The Commission will not specify a method for allocating such costs. Although the Commission will not require a sunset date for a reservation

fee surcharge for gas supply realignment costs, all parties to the restructuring proceedings are encouraged to consider terminating the surcharge on a date certain.[286]

In the NOPR, the Commission noted that take-or-pay costs and buyout/buydown costs have been recoverable under the provisions of Order No. 528, where pipelines agree to absorb at least 25 percent of such costs, unless the pipeline has implemented a market-based price for its gas sales. The NOPR proposed that pipelines be able to continue to seek recovery of such costs through an Order No. 528 mechanism after restructuring, if they did not implement a market-based price for gas sales. The NOPR sought comment on whether some other mechanism would be more appropriate, with or without an absorption requirement, for recovery of gas supply realignment costs that result from compliance with this rule.

After considering the comments on this issue, the Commission has concluded that pipelines should be entitled to recover 100 percent of their prudently incurred gas supply realignment costs that result from compliance with this rule. However, the Commission will not allow the pipelines to recover 100 percent of the costs until the Commission determines they have fully complied with the final rule. Thus the policies of Order Nos. 500 and 528, under which pipelines absorbed a percentage of take-or-pay costs will generally not be applicable

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286. While not imposing a sunset date, the Commission will, three years after the effective date of this rule, audit each pipeline's remaining gas supply contracts to ensure that the pipeline has sought, with due diligence, to realign its contracts to reflect its obligations brought about by this rule. If pipelines and their customers agree to a sunset date for filing for recovery of new gas supply realignment costs within this three year period, the Commission will not audit that pipeline's gas supply contracts.

to recovery of gas supply realignment costs attributable to this rule,[287] although the policies of Order No. 528 will continue to apply until the pipeline fully complies with the provisions of this rule.

The policies of Order Nos. 500 and 528 were designed to encourage pipelines to share some of the cost of the extraordinary take-or-pay liabilities of the early and mid-1980's. The Commission does not anticipate that pipeline gas supply costs that are incurred as a result of implementing this rule will approach the order of magnitude of the take-or-pay liabilities of that era. For one thing, pipelines should now have gas supply contracts that are more responsive to the pipelines' markets. Customers will undoubtedly weigh the effects of paying the gas supply realignment costs in deciding whether to reduce their purchase obligations to pipelines under currently effective contracts or to take assignment of their share of the pipelines' current contracts. Although pipelines will not be asked to bear any prudently incurred gas supply realignment costs they will incur as a direct result of the restructuring required by this rule, they will not be afforded protection from challenges to their prudence in this matter.[288]

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287. On the other hand, if a pipeline has filed for recovery of take-or-pay or contract realignment costs under Order No. 528, the policies of that order continue to apply to those costs. Such costs may not be recharacterized as costs attributable to the requirements of this rule.

288. Nor should LDCs' actions in restructuring proceedings be exempt from prudence challenges under applicable law in proceedings before state regulatory commissions. As the Commission stated in Order No 528-A: "[I]ts action in authorizing interstate pipelines to charge LDCs for take-or-pay costs should not be viewed as preventing action by the state commissions to require partial absorption of those costs by LDCs in accordance with federal and

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The third type of costs, stranded costs, are costs now incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services. For example, pipelines may retain unclaimed or unneeded upstream pipeline capacity even after assignment of portions of that capacity to their firm transportation customers. Similarly, the pipelines may have unbooked, open-access, contract storage beyond their storage needs for balancing and system management.

Stranded costs and the fourth type of costs, for new facilities, should be treated like all other prudently incurred costs, and the pipeline should file to recover such costs in a general rate filing under NGA Section 4. Including new facilities costs and stranded costs for consideration in a general rate case will permit a full review of their legitimacy, and case-specific decisions on how to allocate these costs. While the Commission anticipates that most of the costs of new facilities would be includable in rate base, and therefore affect reservation fees for transportation services or the demand charge component of other services, there is no way of anticipating the nature and amount of the stranded costs, and thus no way at this time of devising an appropriate billing mechanism on a generic basis.

2. Discussion of Comments

Most of the commenters, including LDCs, support the

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state law." Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 54 FERC ¶ 61,095 at p. 61,308 (1991). *See also* Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission, 837 F.2d 600 (3d Cir. 1988), *cert. denied*, 488 U.S. 941 (1988); and Pike County Light and Power Company v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-738 (1983).

ability of the pipelines to recover 100 percent of their prudently incurred transition costs, although no commenter proposed any specific, detailed, cost recovery mechanism.[289] Virtually all of the comments on transition costs addressed gas supply costs. Pipelines propose that recovery of gas supply costs, incurred to realign contracts with producers as a result of implementing this rule, should be through a direct bill or exit fee, not through a commodity surcharge, which they argue would put them at a disadvantage in a highly competitive market.[290] Producers also favor a direct bill mechanism, arguing that volumetric surcharges will result in lower netback prices to them.[291] On the other hand, LDCs and state commissions generally favor volumetric surcharges, and oppose direct bills, which they argue will encourage bypass by large industrial end users.[292] The California Public Utilities Commission argues for partial absorption of gas supply costs by pipelines as an incentive to minimize transition costs. Several LDCs propose that the Commission authorize pipelines to amend their contracts with producers to avoid the

289. *See, e.g.*, Associated Gas Distributors, Brooklyn Union Gas Company, and United Distribution Companies.

290. *E.g.*, Enron Interstate Pipelines, National Fuel Gas Supply Corporation, Natural Gas Pipeline Company of America, Tenneco Gas, and Panhandle Eastern Pipeline Group.

291. *E.g.*, Independent Petroleum Association of America, MESA Limited Partnership, Natural Gas Supply Association and Indicated Producers, and Yates Petroleum Corporation.

292. *E.g.*, Distributors Advocating Regulatory Reform, Michigan Consolidated Gas Company, Northern Indiana Public Service Company, New England Conference of Public Utility Commissioners, National Association of Regulatory Utility Commissioners, and Alabama Public Service Commission.

costs of supply no longer needed as a result of restructuring, and some suggest that producers' access to transportation service should be conditioned on granting the pipeline relief from its contractual obligations for such supply.[293]

The Commission is authorizing 100 percent recovery of prudently incurred gas supply realignment costs incurred as a result of the full implementation of the rule because of the further significant industry-wide restructuring imposed by the Commission in this rule. Any indication that pipelines were lax in their efforts to minimize gas supply realignment costs will be subject to a challenge for prudence and careful scrutiny by the Commission, as discussed above.

In Order No. 500 the Commission adopted rules to allow the pipelines to recover prudently incurred contract reformation costs. That program has been in place for over four years. Indeed, the Commission has found that the take-or-pay problem has been "substantially resolved."[294] The Commission is strongly encouraging pipelines to take additional steps, as soon as possible, to realign their obligations to sell gas resulting from customer choices brought about by this rule.

Pipelines must be able to show that any gas supply realignment costs for which they seek 100 percent recovery are attributable to their actions taken in response to this rule, and that such costs have been minimized by vigorous arms-length

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293. *E.g.*, City of Colorado Springs, Mobile Gas Service Corporation *et al.*, Northern Distributor Group, and Pacific Gas and Electric Company.

294. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. [Regulation Preambles 1986-1990] ¶ 30,867 at p. 31,523 (Order No. 500-H).

negotiations with their producer/suppliers. Thus the possibility of having to defend the incurrence of such costs, and suffer disallowance of recovery, should provide sufficient incentive for pipeline diligence in minimizing these costs.

A fixed surcharge on firm transportation reservation rates is selected (traditionally called a "demand surcharge"), because it passes through the pipeline's costs of adjusting its gas supply inventory to the customers whose choices give rise to the costs, and the customers that will benefit from the unbundling and restructuring required by this rule. The reservation fee surcharge mitigates some of the "net-back" effect on wellhead prices of a volumetric surcharge on all throughput, which might jeopardize the ability of producers to develop new gas supplies by lowering wellhead prices even more than current market conditions have already. The Commission has already explained in detail in Order Nos. 500-H and 500-I why it does not choose to try to revise producer contracts under NGA section 5.[295] While in Order No. 500-H, the Commission conditioned producers' access to transportation service on their willingness to give the pipelines certain credits against the pipelines' take-or-pay obligations, the Commission is very reluctant to create disincentives to producers to market their available reserves to willing buyers by requiring them to relinquish their contractual rights, or placing other conditions on their access to willing buyers in the marketplace.

Several LDCs and state commissions ask that an LDC not be assessed transition costs attributable to former industrial customers that have by-passed their system, and now receive

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295. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 (Order No. 500-H), *order on reh'g*, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,880 (Order No. 500-I).

service directly from the interstate pipeline that serves the LDC.[296] The Commission will consider requests from LDCs for two forms of relief, where they can show a direct nexus between the by-pass and the costs at issue: (1) a reduction in an LDC's contract demand and reservation fee charges, with the industrial customer picking up the LDC's reduced portion directly, and (2) a transfer from the LDC to the industrial customer of the LDC's share of transition costs that are attributable to that customer. Although the Commission has denied similar requests for relief in the past,[297] and will not grant generic relief here to LDCs in this situation, it will consider requests for such relief concerning future transactions in the context of the new regime of this rule on a case-by-case basis.

3. Great Plains Gas

The Dakota Gasification Company (Dakota), the current owner of the Great Plains Gasification Project, which operates a plant for the conversion of coal into synthetic natural gas, requests that a special billing mechanism be authorized for any of the pipelines that purchase gas from the project, if they terminate their PGA mechanisms and implement market-based pricing of gas under this rule. The synthetic gas from Great Plains is priced substantially above current market clearing prices. Dakota also requests that the firm transportation capacity on such pipelines used for transportation of the synthetic gas

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296. Illinois Power Company, Tennessee Valley Municipal Gas Association, United Distribution Company, and Illinois Commerce Commission.

297. *See* Northern Illinois Gas Company v. Natural Gas Pipeline Company of America, 47 FERC ¶ 61,396 (1989), 48 FERC ¶ 61,337 (1989), 49 FERC ¶ 61,098 (1989), 56 FERC ¶ 61,215 (1991).

not be subject to abandonment in the restructuring proceedings. Dakota notes that the Commission recently approved a settlement in the restructuring proceeding of Transcontinental Gas Pipeline Corporation (Transco) that provided for a volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to its obligations to purchase synthetic gas from Great Plains.[298]

There are three other pipelines that purchase synthetic gas from Great Plains — ANR Pipeline Company, Natural Gas Pipeline Company of America, and Tennessee Gas Pipeline Company. The Commission will consider any proposals in these pipelines' restructuring proceedings for a special billing mechanism and special treatment for the associated transportation capacity for Great Plains gas consistent with the precedent in the Transco proceeding.

C. Schedule and Procedures

1. Summary

As proposed in the NOPR, the Commission intends to rely initially on the parties in the restructuring proceedings on each pipeline system to work out the details of compliance with this rule. To this end, the Commission is instituting restructuring proceedings (the RS proceedings) for each interstate pipeline affected by this rule by means of the notice issued contemporaneously with this rule. Section 284.14 is added to the general provisions of part A of Part 284, as a temporary provision to govern the implementation of this rule. The process of implementation thus begins with the issuance of this order

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298. Transcontinental Gas Pipe Line Corporation, 55 FERC ¶ 61,446 at p. 62,332 (1991).

and notice. Interested parties may file motions to intervene in each RS docket within 30 days after issuance of this rule. The pipeline or any other interested party may file a motion to consolidate the RS proceedings with any related pending proceedings within 45 days of issuance. In addition, if a pipeline believes that any part of its existing services, tariff provisions, and rates already comply fully with the provisions of this rule, it can inform the Commission at this time. The pipeline must support its belief with a detailed explanation of how its tariffs already comply with the different features of the rule. The Commission will act promptly to review any such claim so that the pipeline and other interested parties will know whether, and if so, what further action will be needed by the pipeline to fully comply with this rule.

No later than 60 days after issuance of this order, pipelines must initiate discussions on implementation of the rule with the intervenors in their assigned RS proceeding. Pipelines must serve each intervenor in their RS proceedings a summary of their proposals for full compliance with the rule, including *pro forma* rates, no later than 90 days after issuance of this order. Also, to facilitate timely and full compliance, the Commission's staff will convene a pre-filing conference in each RS proceeding, within a reasonable period of time after the pipeline's summary proposal has been served, but before the pipeline's deadline for making its compliance filing, to assist the parties in developing the full range of issues to be addressed on that system and structuring the shape of the compliance filings.

Each pipeline is assigned a deadline in the new section 284.14 and the companion notice for making its tariff filings to comply fully with this rule. The first group of filings will be due by October 1, 1992, and the three remaining groups of filings

are due by November 2, 1992, December 1, 1992, and December 31, 1992, respectively. These compliance filings should be made earlier than these deadlines, if possible. The effective date (or dates) of the full implementation of each pipeline's compliance will be subject to Commission approval on a case-by-case basis. The Commission will issue an order on each compliance filing, either accepting it for implementation on a prospective basis or establishing appropriate procedures. A timeline showing this implementation schedule is appended to this order. The Commission expects to act on all compliance filings in time for all pipelines to implement this rule sufficiently in advance of the 1993-94 winter heating season to provide customers with an adequate opportunity and adequate time to schedule necessary services for that season.

2. Discussion

As discussed above, the Commission has found that the current regulatory structure, and in particular the pipelines' existing bundled, city-gate, firm sales service, is and will continue to be an unreasonable restraint of trade which causes competitive harm to all segments of the natural gas industry because, among other things, it provides the pipelines with an undue advantage and subjects other gas sellers to an undue disadvantage. Therefore, the Commission has found that the pipelines' bundled, city-gate firm sales service violates Sections 4(b) and 5(a) of the Natural Gas Act. Accordingly, the Commission is adopting remedies that must be complied with as soon as possible to remedy the violations of the Natural Gas Act promptly and to eliminate the anticompetitive conditions that currently exist.

To that end, the Commission seeks to ensure that all

pipelines will be in full compliance with the final rule for the 1993-1994 winter heating season. While the Commission anticipates that many pipelines will be able to implement all required elements of the final rule in advance of the 1992-93 winter heating season, other pipelines may not be able to formulate specific proposals and complete their negotiation with all interested parties as expeditiously for various pipeline-specific reasons. Meaningful implementation of this rule on each pipeline system will require existing sales and transportation customers, competing gas merchants, and other interested parties to have an opportunity to consider the various sales, transportation and storage services that will result from the final rule, and to work out the operational details with the pipeline, sufficiently in advance of the winter heating season to permit the development of strategies for meeting peak season demand. At least for some pipelines, it appears unlikely that implementation of this rule would be complete in time for the 1992-93 winter heating season. Therefore, while the Commission strongly encourages compliance with this rule this calendar year, on balance the Commission has concluded that it should not require full compliance with this rule until the 1993-94 winter heating season. This will afford the pipelines and interested parties enough time to work out the operational details and make all adjustments necessary. The Commission does not anticipate any reason for further delay in implementation.

Considerable benefit will be realized from implementation of the final rule by all pipelines in the same general time frame, rather than staggered over several years. A coordinated implementation can facilitate the development of market centers, the allocation of capacity between upstream and downstream pipelines and their users, and the allocation of storage facilities. It will also permit market participants to develop more options

for the delivery of gas out of any given supply basin or into any given city-gate market using a single or multiple pipeline paths and storage combinations. Also, by starting now towards full implementation for the 1993-94 winter season, parties will be able to arrange for the full range of storage service options for that winter heating season, because the storage injection season begins as early as March 1 of the preceding spring for some pipeline systems.

Another side of enabling market participants to evaluate all service options contemporaneously, is that they can also evaluate all the costs associated with the available options, especially transition costs, and develop a strategy that will best mitigate the transition costs. In the Commission's view, reliance on well-informed customer choices is the best way to minimize transition costs, rather than delaying, deferring, or phasing-in critical elements of this rule.

The phasing-in of the requirements of this rule would not be consistent with the Commission's goals here. The unbundling of sales and transportation services makes it possible for the Commission to permit pipelines to sell gas under the blanket sales certificates on a basis analogous to unregulated sellers. It also enables the Commission to ensure that transportation and storage will be available for all gas supplies on equal terms. Unbundling in combination with the new no-notice transportation service, access to storage, the capacity release mechanisms, and other capacity adjustment mechanisms in this rule will enable market participants to function without the anticompetitive influences from the past regulatory environment. Unless these are all implemented in a generally contemporaneous time frame, past restrictions on the functioning of the market will continue, and the Commission's purposes here

may not be achieved within a reasonable period of time. More importantly, these provisions must be implemented contemporaneously in order for market participants to be able to replicate the bundled service provided by pipelines today. These considerations have guided the Commission's development of the implementation procedures and schedule discussed below.

The notice issued contemporaneously with this order assigns an RS docket number to each pipeline restructuring proceeding. If a pipeline believes that its existing tariffs or settlements already filed with the Commission achieve the full objectives of this rule, or that a proceeding currently pending before the Commission constitutes an appropriate vehicle for its compliance with this rule, it must file a motion in the RS docket with the Commission within 45 days after issuance of this order, setting forth the basis for its belief and indicating whether it wants to terminate the currently pending proceedings, consolidate them with the RS docket, or terminate the RS docket.

The Commission will act promptly to address any such requests, so parties can have the benefit of the Commission's views before they have to engage in discussion under the restructuring requirements of the rule. If the Commission agrees that any or all aspects of a pipeline's current services, tariff provisions, or rates comply fully with the rule, then there is no need for the parties to engage in the restructuring proceedings established here, or at least as to the aspects that already fully comply. The Commission may not be able to provide this guidance before the parties are required to begin discussion under the timetable established in this order. However, the Commission will endeavor to act on these filings as quickly as it can.

Appendix B

Motions to intervene in the restructuring proceedings after the pipelines' compliance filings to fully implement the rule are made will not be viewed with favor. The speed and success of implementation of this rule will depend largely on the involvement of all interested parties (including producers, shippers and potential shippers, marketers, state commissions, and end-users, as well as small, large, and medium-sized LDCs) in the discussions that will precede the pipelines' filings to comply with the rule, and the attempted intervention of interested parties after those discussions have culminated in the compliance filings will generally be disruptive.

The Commission encourages the pipelines to develop a consensus on, or substantial support for, their plans of full implementation before making the required restructuring filings, if possible. To this end, this order requires each pipeline affected by this rule to initiate discussions with its customers and other interested parties no later than 60 days after issuance of this order. Each pipeline must serve a summary of its proposed plan of full implementation to the intervenors no later than July 7, 1992, following the procedure used by the Commission's litigation staff for serving "top sheets" in a rate case. This summary must include a description of how the pipeline proposes to implement fully all aspects of the final rule, including any terms and conditions the pipeline proposes for maintaining operational control of its system and the reasons why the pipeline believes these are necessary, and *pro forma* illustrative rates for the restructured services.

Furthermore, the Commission is directing its staff to convene at least one conference in each restructuring proceeding prior to the pipeline's deadline for making its restructuring filing. These will be publicly noticed conferences, convened for the

purpose of assisting the pipeline and interested parties in delineating the issues that need to be resolved in the pipeline's compliance filing and to discuss the structure of that filing. The conference in each proceeding should be convened no sooner than 90 days nor later than 180 days after issuance of this order. The conferences may be convened at locations that are convenient to the representatives of the pipeline and intervenors, not necessarily at the Commission's headquarters in Washington, D.C. The Commission staff will report to the Commission, if needed, the status of pre-compliance filing discussions at the public conference to assist the Commission in identifying early any problems that may be hindering the full and timely implementation of this rule.

The nature of the pipelines' filings may vary somewhat, depending on the extent to which the pipeline has previously incorporated features required by this rule into its current tariff and portfolio of services. However, all of the pipelines' filings will be compliance filings pursuant to the Commission's findings and rulings in this final rule under Section 5 of the Natural Gas Act (NGA), and authorizations granted under NGA Section 7.

The Commission recognizes that some components of the restructured rates will be higher than the same component (or an equivalent component) under existing rates. However, the pipelines are required to submit *pro forma* tariff sheets that are based on the same cost of service and total throughput as their currently effective rates. Thus, the restructuring will not result in any overall increase in rates. Where changes in rate design result in rate increases in certain components of the rates, or to certain customers or customer classes, the Commission will permit the increases in the compliance filing because it is related

to a Commission directed modification in the pipeline's rate structure.[299]

Furthermore, pipelines may file notices of rate changes pursuant to Section 4 of the NGA in conjunction with their restructuring filings that have no direct relationship to the required restructuring, but simply reflect changes in costs or throughput. The pipelines may also seek rate increases due to implementation of this rule in a NGA Section 4 filing. However, whether filed to reflect changes due to restructured rate design or other things, such notices of rate changes should be filed separately from the restructuring filings, and will be assigned different docket numbers, because the effective dates of rate changes filed under Section 4 will not necessarily coincide with the effective dates of the restructuring filings.[300] Pipelines will not be permitted to implement contested features of their restructuring proposals prematurely by incorporating them in a separate Section 4 filing.

The pipelines should propose effective dates for their restructuring that will provide for full compliance sufficiently in advance of the 1993-1994 heating season, as discussed above. Many commenters have suggested that unbundling should not be implemented just prior to or during a peak-load season. As

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299. *See* ANR Pipeline Co. v. FERC, 863 F.2d 959 (D.C. Cir. 1988) (Commission can permit rate increases as part of compliance filing to implement Commission directed modifications under Section 5(a) of the NGA.).

300. Also, as discussed above, the final Policy Statement on Incentive Ratemaking will address the relationship, if any, between the final rule in these dockets and the filing of any incentive ratemaking proposals for non-competitive pipeline services.

discussed previously, the Commission concurs. Because the effective date of full implementation will not occur until the Commission accepts the tariff sheets in the compliance filing, the Commission will ensure that no pipeline has to implement the rule during a peak-load season.[301] The Commission strongly believes that all of the pipelines affected by this rule will be able to implement the full requirements of this rule for the 1993-1994 winter heating season. Thus, most pipelines should be fully unbundled in compliance with this rule by the spring or summer of 1993. In any event, the effective dates for each plan will be subject to Commission approval on a case-by-case basis, in view of the degree of support by interested parties and conformity to the goals and requirements of this rule. However, the Commission will not tolerate delays that would prevent implementation for the 1993-1994 heating season.

The compliance filings must address each and every feature of the restructuring required by this final rule and include a detailed explanation of how the pipeline intends to implement those features. They *must* include tariff provisions to implement all of the elements in new section 284.14, including unbundled sales, storage, and transportation service on an open access, nondiscriminatory basis, to achieve full equality of service, and to allocate capacity rights on the pipeline's facilities and on upstream pipelines to the pipeline's firm customers.[302] There must be tariff provisions specifying the operational conditions necessary to provide no-notice transportation service, maintain adequate pressure and reliable service at all times, and specifying

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301. However nothing here precludes early implementation if the pipeline and the parties agree otherwise.

302. Pipelines with storage facilities must provide detailed explanation and support for their proposed allocation of storage capacity among services.

procedures for operating under curtailment of gas supply or capacity. These filings must also include tariff provisions to implement a capacity release program in conformity to the requirements of this final rule.

The *pro forma* rates must reflect the currently approved cost of service and incorporate the straight fixed variable method of rate design unless the Commission approves otherwise. As discussed in Section VIII, *supra*, the filing must include a comparison of the revenue responsibility of each of the pipeline's historic customer classes under SFV and the pipeline's last approved cost classification method. If the revenue responsibility of any class increases 10 percent or more, the pipeline must also include a phase-in plan for implementation. The filing must include detailed explanations of the reasons for each of the pipeline's proposed rates, tariff provisions, and operational provisions, and must include the pipeline's estimate of the costs it expects to incur as a result of complying with this final rule, and any mechanisms proposed to recover those costs. Additionally, pursuant to the Notice of Proposed Policy Statement on Incentive Regulation (Docket No. PL92-1-000), issued March 13, 1992,[303] the Commission is receiving public comment on incentive ratemaking. In issuing the notice of proposed policy statement, the Commission recognized that the pipelines may want to utilize incentive ratemaking proposals as a competitive tool in the restructuring proceedings. Subject to the Commission's actions in the final policy statement on incentive regulation,[304] the pipelines may wish to file an

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303. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, 58 FERC ¶ 61,287 (1992).

304. The Commission expects to issue a final policy statement on (Cont'd)

incentive rate proposal along with its restructuring compliance filing. Any such incentive ratemaking proposal filed contemporaneously with the restructuring compliance filing should include sufficient detail to demonstrate the effect of the incentive rates on the straight fixed-variable (SFV) and unbundling objectives discussed above. Additionally, any incentive rate proposal must have the full support of the parties to the restructuring proceedings and be consistent with the Commission's final policy statement.

Some of the commenters assert that it may take some pipelines as much as two years to work out the operational details necessary to ensure reliable and efficient operation in an unbundled environment, without costly new facilities. The Commission disagrees and will not tolerate any unnecessary delay in compliance with this order. Pipelines will bear a heavy burden of persuasion for any request for additional time to postpone full implementation beyond what is necessary for implementation for the 1993-1994 winter heating season. In no event will the Commission permit pipelines to begin charging market-based rates for gas, to make unconstrained ISS sales, or to recover 100 percent of their transition costs, before the Commission determines (by acceptance of the compliance tariff sheets) that they have complied fully with this rule.

The Commission will issue orders on the restructuring filing, and establish further procedures if necessary in view of protests or other comments on the pipeline's filing. The Commission hopes that pipelines and interested parties will achieve a

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Incentive Ratemaking of Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities as soon as possible after the close of the period for public comment on April 27, 1992.

consensus on most features of the restructuring filing before it is filed. If the filing enjoys substantial support, no substantial opposition, and is in compliance with the requirements of this final rule, the Commission will permit the pipeline's proposal to be implemented on a prospective basis in short order.

The Commission will use procedures designed to achieve the most expeditious resolution of any contested issues raised with respect to the restructuring filings. If elements of the compliance filing are in patent conflict with the requirements of this final rule, or other applicable law or policy, the Commission may make summary dispositions on the merits. If review of a pipeline's compliance filing indicates that a pipeline will not achieve full compliance with this rule on a timely basis, the Commission may issue an interim compliance order, to provide direction to the pipeline on the steps necessary to correct deficiencies in its proposal soon enough to avoid delay in implementation of this rule. If there is substantial opposition to the pipeline's plan, but indications that further settlement discussions may resolve the points in dispute expeditiously, the Commission may direct the staff to convene settlement conferences and establish a deadline for submission of a report on the status of the settlement discussions. In proceedings where there are disputed issues that require development of a record, but not necessarily by means of a trial-type hearing, the Commission may use expedited "paper hearing" procedures. The Commission does not intend to require development of a record in a trial-type hearing; therefore the restructuring proceedings will not be set for hearing before administrative law judges unless they are consolidated with other proceedings already pending before a judge.

In several recent cases, the Commission has reviewed

"contesting party provisions" in settlement proposals that appeared to coerce parties into waiving their statutory rehearing and appeal rights by denying them certain services if they seek rehearing or judicial review of an order accepting the settlement.[305] These cases raise the specter that pipelines in restructuring proceedings under the final rule will seek to incorporate such provisions into unilateral settlement offers. The Commission is encouraging the development of settlements to implement this rule. However, as a matter of public policy, the Commission will not tolerate coercive provisions included in a pipeline's offer of settlement that have the effect of forcing parties to acquiesce in a settlement, or parts of a settlement, by threatening the denial of essential services.[306] Thus, a pipeline cannot deny access to its open access storage services, unbundled firm and interruptible transportation services, no-notice delivery service, or capacity release program to a party that contests some provision of its settlement proposal in a restructuring proceeding. The Commission will resolve the issues in contested settlements on the merits, and avoid any question of contesting parties being denied essential services while litigating the contested issues.

To a large extent, the date by which each pipeline fully implements the restructuring required by this rule will depend on the diligence and good faith of the pipeline and interested parties. The Commission has established deadlines for filings and has provided direction for making those filings. The Commission will continue to provide direction and guidance for fully implementing the policies reflected by the requirements of this rule. The Commission respects the rights of pipelines

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305. *See* Tennessee Gas Pipeline Co., 57 FERC ¶ 61,360 (1991); and CNG Transmission Corp, 55 FERC ¶ 61,189 (1991).

306. *See* CNG Transmission Corp., 55 FERC at p. 61,643.

and interested parties to differ over how these policies should best be implemented on a particular pipeline system. However, the Commission will not abide recalcitrance in the restructuring proceedings. If the pipeline's filings are not in compliance with the requirements of this rule, and the pipeline and interested parties cannot resolve differences over what is required to bring the pipeline into full compliance, the Commission will resolve the disputes on the merits. And once the Commission has determined how this rule must be implemented on a particular pipeline system, it will bring the full panoply of its enforcement resources to bear to ensure compliance with its decision.

3. Other Matters

A number of pipelines have urged the Commission to exempt them from the final rule because, they allege, their unique circumstances make applicability of the rule inappropriate. Northern Border Pipeline Company, Overthrust Pipeline Company, Ozark Gas Transmission System, Trailblazer Pipeline Company, and Wyoming Interstate Company argue that the Commission must recognize their unique status as project-financed pipelines and allow flexibility with regard to compliance with the rule. These pipelines state that the provisions regarding capacity reallocation may create problems for them because their lenders have relied on the credit standing of their firm transportation customers as collateral. They assert that assigning capacity to other shippers may necessitate restructuring of their credit agreements or may put them in default. Northern Border also argues that it should be allowed to continue to use its cost-of-service rate design because it is similar in concept to SFV and is appropriate for a transportation only pipeline. Several of these pipelines cite *Ozark Gas*

Transmission System v. FERC,[307] as holding that the Commission cannot approve a project-financed pipeline, and then later impose conditions that jeopardize its financing.

The capacity releasing program adopted by the final rule will not jeopardize the financing arrangements of these pipelines. As explained above, unless the pipeline otherwise agrees, the firm transportation customer releasing capacity will remain liable on its contract with the pipeline but will receive a credit against its bill on the capacity resold. Thus, the customers whose credit standing has been relied upon by the lenders remain the same. The appropriate rate design for project financed pipelines may be addressed in the individual restructuring proceedings.

Freeport Interstate Pipeline, Pacific Interstate Offshore Co., Pacific Offshore Pipeline Co., and Superior Offshore Pipeline Company and Texas Sea Rim Pipeline, Inc. argue that compliance with the rule is not necessary or appropriate for them because they are small, special purpose, Outer Continental Shelf (OCS) pipelines, generally serving only one customer. Similarly, Alabama-Tennessee Natural Gas Company and Gas Transport, Inc. argue that they should be exempt from the final rule because they are small, non-major pipelines. Gas Transport asserts that administrative costs and burdens will be disproportionately large for small pipelines.

These non-major and OCS pipelines may be required to make few, if any, changes to bring their operations into compliance with the rule, particularly if they provide transportation service only. However, the Commission will not adopt a general exemption for all OCS and non-major pipelines.

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307. 897 F.2d 548 (D.C. Cir. 1990).

Instead, the Commission will direct these pipelines to file in a restructuring proceeding and the Commission will address the appropriate requirements for each pipeline in those proceedings.

Great Lakes Transmission Limited Partnership states that the release of upstream capacity is impossible for pipelines transporting Canadian gas from the International Boundary. Great Lakes asserts that much of this gas is subject to regulation by both Canadian and U.S. authorities and that some of the provisions of the rule may be inconsistent with Canadian gas regulation. Great Lakes argues that the rule must be amended to recognize that independent multi-national transportation agreements exist which are subject to international regulation.

Section 284.282 of the final rule provides that downstream pipelines must allocate their capacity on upstream pipelines to firm customers, if the upstream pipeline provides transportation under Subpart B or G of Part 284 of the Commission's regulations. Any problems that arise in the implementation of this rule because of the character or nature of certain pipeline transactions will be addressed on a case-by-case basis in the restructuring proceedings.

XII. ENVIRONMENTAL ANALYSIS

The Commission concludes that the final rule does not represent a major federal action having a significant adverse impact on the human environment under the Commission's regulations implementing the National Environmental Policy Act.[308] The final rule falls within the categorical exemption provided in the Commission's regulations for the review of rates

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308. 18 CFR Part 380.

for the transportation and sale of natural gas under sections 4 and 5 of the NGA[309] and for the sale, exchange, and transportation of natural gas under sections 4, 5, and 7 of the NGA[310] that require no construction of facilities. If construction is proposed in the future, it will be evaluated in individual proceedings. Consequently, neither an environmental assessment or an environmental impact statement is required.

In comments on the NOPR, the Panhandle Customer Group objects to this finding because, they allege, the rule effectively requires LDCs to construct storage and transmission facilities and would encourage producers and marketers to construct new gathering facilities. The Panhandle Customer Group argues that the Commission must consider alternatives to the proposed rule that would result in less construction activity.

The assertions of the Panhandle Customers are entirely unsubstantiated. Nothing in the rule directs or authorizes construction of any facilities. Impacts of future construction will be evaluated by the Commission or by the appropriate environmental authority if a specific proposal is presented.

XIII. REGULATORY FLEXIBILITY CERTIFICATION

The Regulatory Flexibility Act (RFA)[311] generally requires a description and analysis of rules that will have a significant economic impact on a substantial number of small entities.

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309. 18 CFR 380.4(a)(25).

310. 18 CFR 380.4(a)(27).

311. 5 U.S.C. 601-612 (1988).

Pursuant to section 605(b) of the RFA, the Commission certifies that the final rule will not have a significant impact on a substantial number of small entities.

In comments on the NOPR, the Panhandle Customer Group objects to this finding, alleging that the rule will have a severe economic impact on small LDCs that serve largely residential loads. They assert that elimination of unscheduled delivery service will require expenditures for electronic metering and computing equipment, and that adoption of the SFV rate design and the capacity releasing program will have an economic impact.

Again, these allegations are unsubstantiated.[312] The Commission has explained above why the rule will not have an adverse economic impact on any LDC, large or small.

XIV. INFORMATION COLLECTION

The Office of Management and Budget's (OMB) regulations require that OMB approve certain information collection requirements imposed by agency rules.[313]

In the NOPR, the Commission estimated the public reporting burden for the collection of information in the proposed rule to average 4,810 hours per response under FERC-544, Gas Pipeline Rates: Rate Change (Formal) (1902-0153). The total reporting burden associated with the proposed rule was estimated to be 408,850 hours. The estimate included time for reviewing

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312. In any event, the rule does not eliminate no-notice service.

313. 5 CFR Part 1320.

the requirements adopted in the rule, searching existing data sources, gathering and maintaining the data needed, completing and reviewing the collection of information and filing this information with the Commission. In the NOPR, the Commission stated that interested persons could file comments regarding this burden or other aspects of this collection of information, including suggestions for reducing this burden, to the Commission. No comments were received on the public reporting burden. The final rule establishes certain requirements and information collections that differ slightly from the NOPR.

The information collection forms affected by the final rule are: FERC-545, Gas Pipeline Rates: Rate Change (Non-formal), (1902-0154); FERC-549, Gas Pipeline Rates: NGPA Title III Transactions; Ceiling Prices; Old Gas Pricing Structure, (1902-0086); and FERC-592, Marketing Affiliates of Interstate Pipelines (1902-0157). These information collections are required in order for the Commission to carry out its legislative mandate under the NGA and the NGPA. The information required by the final rule will allow the Commission to ensure that firm transportation service provided under Part 284 of the Commission's regulations for nonpipeline sellers is equal to transportation service associated with a pipeline's firm sales service.

An estimated 89 respondents will be affected by this rule. The respondents will consist of pipeline companies subject to the Commission's jurisdiction that perform self-implementing transportation under either the NGA or the NGPA. The Commission finds that: (a) the public reporting burden will average 4,810 hours per response under FERC-545, 2.7 hours per response under FERC-549, and 9.94 hours per response under FERC-592. The annual reporting burden will be 428,090

hours for FERC-545, 410 hours for FERC-549, and 885.2 hours for FERC-592, for a total estimated burden of 429,385.2 hours; (b) the frequency of response under FERC-545 will be a one-time filing by respondents; (c) for the other data collections the number of annual responses will vary. The Commission anticipates that the public reporting burden will decrease substantially after the one-time implementation filings have been made.

XV. EFFECTIVE DATE

This Final Rule is effective [insert date 30 days after publication in the *Federal Register*].

List of subjects in 18 CFR Part 284

Continental shelf
Natural gas
Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission amends Part 284, Chapter I, Title 18, *Code of Federal Regulations,* as set forth below.

By the Commission. Commissioner Langdon concurred in part and dissented in part with a separate statement attached.

(SEAL) Commissioner Terzic concurred with a separate statement to be issued later.

Lois D. Cashell,
Secretary.

Appendix B

PART 284 — CERTAIN SALES ANDTRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

1. The authority citation for Part 284 continues to read as follows:

Authority: 15 U.S.C. 717-717w; 15 U.S.C. 3301-3432; 43 U.S.C. 1331-1356; 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR, 1978 Comp., p. 142.

2. In § 284.1, paragraph (a) is revised and a new paragraph (c) is added to read as follows:

§ 284.1 ***Definitions.***

(a) *Transportation* includes storage, exchange, backhaul, displacement, or other methods of transportation.

* * * * *

(c) *Market center* means an area where gas purchases and sales occur at the intersection of different pipelines.

3. In § 284.8, paragraph (a)(1) is revised, new paragraph (a)(4) is added, paragraph (b) is revised by adding paragraph (b)(1) designation after the heading, "*Non-discriminatory access.*" and before the words "An interstate pipeline", paragraphs (b)(2) through (b)(5) are added, and paragraph (d) is revised to read as follows:

Appendix B

§ 284.8 *Firm transportation service.*

(a) *Firm transportation availability.* (1) An interstate pipeline that provides transportation service under Subpart B or G of this part must offer such transportation service on a firm basis and separately from any sales service.

* * * * *

(4) An interstate pipeline that provided a firm sales service on [insert date 30 days after publication in the *Federal Register*], and that offers transportation service on a firm basis under Subpart B or G of this part, must offer a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty.

(b) *Non-discriminatory access.* (1) * * *

(2) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must provide each service on a basis that is equal in quality for all gas supplies transported under that service, whether purchased from the pipeline or another seller.

(3) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must provide all shippers with equal and timely access to information relevant to the availability of such service, including, but not limited to, the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, and whether the capacity is available directly from the pipeline or through capacity release.

Appendix B

(4) The requirement of paragraph (b)(3) of this section must be implemented through the use of an Electronic Bulletin Board on which the pipeline must provide for:

(i) Downloading by users,

(ii) Daily back-up of information displayed on the board, which must be available for user review for at least three years,

(iii) Purging information on completed transactions from current files,

(iv) Display of most recent entries ahead of information posted earlier, and

(v) On-line help, a search function that permits users to locate all information concerning a specific transaction, and a menu that permits users to separately access notices of available capacity, each record in the transportation log, and standards of conduct information.

(5) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part may not include in its tariff any provision that inhibits the development of market centers.

* * * * *

(d) *Reservation fee.* Where the customer purchases firm service, a pipeline may impose a reservation fee or charge on a shipper as a condition for providing such service. Except for pipelines subject to Subpart C of this part, if a reservation fee is charged, it must recover all fixed costs attributable to the firm

transportation service, unless the Commission permits the pipeline to recover some of the fixed costs in the volumetric portion of a two-part rate. A reservation fee may not recover any variable costs or fixed costs not attributable to the firm transportation service. Except as provided in this paragraph, the pipeline may not include in a rate for any transportation provided under Subpart B, C or G of this part any minimum bill or minimum take provision, or any other provision that has the effect of guaranteeing revenue.

* * * * *

4. In § 284.9, paragraph (a)(1) is revised, paragraph (b) is revised by adding paragraph (b)(1) designation after the heading, "*Non-discriminatory access.*" and before the words "An interstate or intrastate pipeline", and new paragraphs (b)(2) through (b)(5) are added to read as follows:

§ 284.9 ***Interruptible transportation service.***

(a) *Interruptible transportation availability.* (1) An interstate pipeline that provides firm transportation service under Subpart B or G of this part must also offer transportation service on an interruptible basis under that subpart or subparts and separately from any sales service.

* * * * *

(b) *Non-discriminatory access.*

(1) * * *

(2) An interstate pipeline that offers transportation service

on an interruptible basis under Subpart B or G of this part must provide each service on a basis that is equal in quality for all gas supplies transported under that service, whether purchased from the pipeline or another seller.

(3) An interstate pipeline that offers transportation service on an interruptible basis under Subpart B or G of this part must provide all shippers with equal and timely access to information relevant to the availability of such service.

(4) The requirement of paragraph (b)(3) of this section must be implemented through the use of an Electronic Bulletin Board with the features required under § 284.8(b)(4).

(5) An interstate pipeline that offers transportation service on an interruptible basis under Subpart B or G of this part may not include in its tariff any provision that inhibits the development of market centers.

* * * * *

5. Section 284.12 is revised by removing the words "May 1" and adding, in their place, the words "March 1", and by inserting the phrase ",and the estimated storage capacity and maximum daily delivery capability of storage facilities," after "pipeline's system" and before "under".

6. Section 284.14 is added to read as follows:

Appendix B

§ 284.14 ***Provisions governing pipeline restructuring.***

(a) *Applicability.*

This section applies to any interstate natural gas pipeline that offers transportation service under Subpart B or G of this part on [insert date 30 days after publication in the *Federal Register*].

(b) *Compliance filing.* (1) The pipelines subject to this section must make a compliance filing on or before the dates set forth in paragraph (b)(4) of this section to implement the provisions of § 284.1(a), § 284.8(a)(1), (a)(4), (b)(2)-(5), and (d), § 284.9(a)(1) and (b)(2)-(5), § 284.221(d), and Subparts H and J of this part, including, but not limited to, tariff provisions to implement without undue discrimination:

(i) Unbundled sales and transportation services,

(ii) Open access storage service,

(iii) Reasonable and non-discriminatory terms and conditions for operating unbundled open-access transportation,

(iv) Equality of transportation service for all gas transported under each rate schedule,

(v) Allocation of aggregate receipt point capacity, individual receipt point capacity, mainline segment capacity, storage capacity, and delivery point capacity,

(vi) Shipper flexibility in changing receipt and delivery points,

Appendix B

(vii) Scheduling of gas injections into the mainline and into storage, scheduling of gas deliveries from storage and from the mainline, the setting and charging of penalties, balancing rights, and the instantaneous receipt and delivery of gas,

(viii) No-notice transportation service, with separately identified cost components,

(ix) Equality of access to information on availability of service,

(x) Non-discriminatory plans for operating under curtailment of capacity and gas supply (if the pipeline sells gas),

(xi) Rate design and cost allocation changes,

(xii) A capacity release mechanism,

(xiii) Right-of-first-refusal procedures for use upon the expiration of long-term, firm transportation contracts, and

(xiv) Assignment of capacity rights on upstream pipelines to firm customers.

(2) The compliance filing must be filed no later than the date specified for each pipeline in paragraph (b)(4) of this section in the restructuring proceeding instituted by the Commission for the implementation of the provisions listed in paragraph (b)(1) of this section.

(3)(i) The changes in rates, charges, classifications, or services, or in any rule, regulation, or service agreement, necessary to comply with this paragraph must be filed as *pro*

forma tariff sheets, for illustrative purposes only, with rates that are designed to recover the same revenue requirement as the pipeline's rates in effect on the date the compliance filing is made.

(ii) The compliance filing must also include a comparison of the revenue responsibility of each of the pipeline's historical customer classes for the unbundled services under

(A) the pipeline's last approved cost classification method for cost allocation and rate design, and

(B) the straight fixed-variable (SFV) cost classification method for cost allocation and rate design.

Under the straight fixed-variable method all fixed costs are classified to the demand component. If the comparison shows that adopting SFV for cost allocation and rate design will result in a 10 percent or greater increase in revenue responsibility for any customer class, the compliance filing must include a plan for phasing-in the cost shift due to SFV over no more than a four year period.

(iii) The compliance filing must also include an estimate of the costs of implementing the provisions of this paragraph and any mechanisms proposed for recovering those costs.

(4) The following pipelines must file on or before October 1, 1992:

ANR Pipeline Company

ANR Storage Company

Appendix B

Arkla Energy Resources

Colorado Interstate Gas Company

Columbia Gas Transmission Corporation

Columbia Gulf Transmission Corporation

Michigan Gas Storage

Northern Natural Gas Company

Questar Pipeline Company

Southern Natural Gas Company

Texas Eastern Transmission Corporation

Williams Natural Gas Company

Williston Basin Interstate Pipeline

The following pipelines must file on or before November 2, 1992:

CNG Transmission Corporation

Equitrans, Inc.

Florida Gas Transmission Company

Iroquois Gas Transmission

Appendix B

Kentucky-West Virginia Gas Company

KN Energy, Inc.

Mid Louisiana Gas Company

National Fuel Gas Supply Corporation

Panhandle Eastern Pipe Line Company

Tennessee Gas Pipeline Company

Texas Gas Transmission Corporation

Trunkline Gas Company

United Gas Pipe Line Company

The following pipelines must file on or before December 1, 1992:

Alabama Tennessee Natural Gas Company

Algonquin Gas Transmission Company

Altamont Gas Transmission Company

Carnegie Natural Gas Company

Cornerstone Pipeline Company

Delta Pipeline Company

Appendix B

East Tennessee Natural Gas Company

Gas Gathering Corporation

Gas Transport Inc.

Gateway Pipeline Company

Green Canyon Pipeline Company

Gulf States Transmission Corporation

Inland Gas Company, Inc.

Louisiana Nevada Transit Company

Midwestern Gas Transmission Company

MIGC, Inc.

Mississippi River Transmission Corporation

Moraine Pipeline Company

Natural Gas Pipeline Company of America

Pacific Gas Transmission Company

Phillips Gas Pipeline Company

Riverside Pipeline Company

Appendix B

South Georgia Natural Gas Company

Valero Interstate Transmission Company

Valley Gas Transmission, Inc.

Viking Gas Transmission Company

Western Gas Interstate Company

Western Transmission Corporation

Wyoming California Pipeline

The following pipelines must file on or before December 31, 1992:

Black Marlin Pipeline Company

Canyon Creek Compression Company

Caprock Pipeline Company

Chandeleur Pipe Line Company

El Paso Natural Gas Company

Freeport Interstate Pipeline Company

Gasdel Pipeline System, Inc.

Great Lakes Gas Transmission

Appendix B

High Island Offshore System

Kern River Gas Transmission Company

Mojave Pipeline Company

Northern Border Pipeline Company

North Penn Gas Company

Northwest Pipeline Corporation

OkTex Pipeline Company

Overthrust Pipeline Company

Ozark Gas Transmission System

Pacific Interstate Offshore Company

Pacific Offshore Pipeline Company

Paiute Pipeline Company

Pelican Interstate Gas System

Point Arguello Natural Gas Line Company

Sabine Pipe Line Company

Sea Robin Pipeline Company

Appendix B

Seagull Interstate Corporation

Stingray Pipeline Company

Superior Offshore Pipeline Company

Tarpon Transmission Company

Texas Sea Rim Pipe Line, Inc.

Trailblazer Pipeline Company

Transcontinental Gas Pipe Line Corporation

Transwestern Pipeline Company

U-T Offshore System

West Gas Interstate, Inc.

Wyoming Interstate Company, Ltd.

(c) *Restructuring discussions.* (1) By June 8, 1992, a pipeline subject to this section must initiate restructuring discussions concerning implementation of the provisions of this section with all its customers and other interested parties that intervene in its restructuring proceeding instituted by the Commission for implementation of the provisions listed in paragraph (b)(1) of this section.

(2) By July 7, 1992, a pipeline subject to this section must prepare and serve a summary of its proposed restructuring plan on every intervenor in its restructuring proceeding, addressing

each and every element of the compliance filing required under paragraph (b)(1) of this section.

(d) *Adjustments to obligations to purchase gas; automatic abandonment of sales.* (1) Any firm sales customer of a pipeline subject to this section may reduce or terminate its right or obligation to purchase gas under any contract with that pipeline for the sale of natural gas in effect on [insert date 30 days after publication in the *Federal Register*] by giving notice to the pipeline during the pipeline's restructuring proceeding.

(2) A pipeline subject to this section is authorized to abandon the sale of gas to any purchaser to the extent (i) the purchaser exercises its right to reduce or terminate its right or obligation to purchase under the provisions of paragraph (d)(1) of this section, or (ii) the purchaser refuses to pay the rate the pipeline offers for unbundled gas sales. The pipeline must file a report of any such abandonment of sales with the Commission within 30 days of the date of abandonment.

(3) The reduction or termination of service under the contract and the abandonment of sales under paragraph (d)(2) of this section will be effective on the effective date (as approved by the Commission) of the tariff sheets implementing service under the pipeline's blanket certificate for unbundled sales services under § 284.284.

(e) *Adjustments to firm transportation service; automatic abandonment.* (1) Any firm shipper on a pipeline subject to this section must give notice to the pipeline during the pipeline's restructuring proceeding that the shipper wants to retain, reduce, or terminate its contractual rights to firm transportation service.

(2) Except as provided in paragraph (e)(4) of this section, a pipeline subject to this section may abandon firm transportation service under a contract with a firm shipper to the extent the shipper gives the notice to reduce or terminate described in paragraph (e)(1) of this section. The authority to abandon service does not apply unless during the pipeline's restructuring proceeding (i) the pipeline executes a contract with another shipper for the transportation rights, or (ii) the pipeline agrees to the reduction or termination of contractual rights.

(3) The authority to abandon service under this paragraph is effective respectively (i) on the effective date of the contract described in paragraph (e)(2) of this section or (ii) on the effective date of the pipeline's agreement to the reduction or termination of contractual rights described in paragraph (e)(2).

(4) Paragraph (e)(1) of this section does not apply to the firm transportation service provided for a downstream pipeline subject to Subpart B or G of this part on an upstream pipeline subject to Subpart B or G of this part.

7. In § 284.106, the introductory text of paragraph (a) is revised by inserting the words "(except storage)" after "transportation" and before "under § 284.102," the introductory text of paragraph (c) is revised by removing the words "May 1" and adding in their place, the words "March 1", and by inserting the words "(except storage)" after "transportation service" and before "provided," and the introductory text of paragraph (d) is revised by inserting the words "(except storage)" after "transportation arrangement" and before "under § 284.102".

8. In § 284.106, a new paragraph (g) is added, to read as follows:

Appendix B

§ 284.106 ***Reporting requirements.***

* * * * *

(g) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline shall file with the Commission a report of storage activity provided under the authority of § 284.102. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(2) The rate schedule under which the storage injection or withdrawal service was performed;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period; and

(6) The related docket numbers in which the interstate pipeline reported storage related injection/withdrawal transportation services.

Appendix B

9. In § 284.126, the introductory text of paragraph (a) is revised by inserting the words "(except storage)" after "transportation" and before "under this subpart," the introductory text of paragraph (c) is revised by removing the words "May 1" and adding, in their place, the words "March 1", and by inserting the words "(except storage)" after "transportation service" and before "provided," and the introductory text of paragraph (d) is revised by inserting the words "(except storage)" after "transportation arrangement" and before "authorized".

10. In § 284.126, a new paragraph (g) is added, to read as follows:

§ 284.126 ***Reporting requirements.***

* * * * *

(g) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the intrastate pipeline shall file with the Commission a report of storage activity provided under the authority of § 284.122. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage;

(2) The docket where the storage injection or withdrawal rates were approved;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer; and

(6) The related docket numbers in which the intrastate pipeline reported storage related injection/withdrawal transportation services.

11. In § 284.221, paragraph (d) is revised to read as follows:

§ 284.221 ***General rule; transportation by interstate pipelines on behalf of others.***

* * * * *

(d) *Pre-grant of abandonment.* (1) Except as provided in §§ 284.14(e), and paragraphs (d)(2) and (d)(3) of this section, abandonment of transportation services is authorized pursuant to Section 7(b) of the Natural Gas Act upon the expiration of the contractual term or upon termination of each individual transportation arrangement authorized under a certificate granted under this section.

(2) Paragraph (d)(1) of this section does not apply if the individual transportation arrangement is for firm transportation under a contract with a term of more than one year, and the firm shipper:

(i) Exercises any contractual right to continue such service; or

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the maximum rate under § 284.7, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching those terms.

(3) Paragraph (d)(1) of this section does not apply where, after February 13, 1991, and before [insert date 30 days after publication in the *Federal Register*], a shipper converted from sales service to firm transportation service under the provisions of § 284.10 or under a separate agreement (to the extent of conversion of pre-existing sales volumes).

* * * * *

12. In § 284.223, the introductory text of paragraph (d)(1) is revised by inserting the words "(except storage)" after "transportation" and before "authorized," the introductory text of paragraph (d)(3) is revised by removing the words "May 1" and adding, in their place, the words "March 1", and inserting the words "(except storage)" after "transportation service" before "provided," and the introductory text of paragraph (d)(4) revised by inserting the words "(except storage)" "transportation arrangement" and before "under this section".

13. In § 284.223, a new paragraph (d)(5) is added, to read as follows:

Appendix B

§ 284.223 ***Transportation by interstate pipelines on behalf of shippers other than interstate pipelines.***

* * * * *

(d) *Reporting requirements.*

* * * * *

(5) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline shall file with the Commission a report of storage activity provided under the authority of this section. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(i) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(ii) The rate schedule under which the storage injection or withdrawal service was performed;

(iii) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(iv) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(v) The unit charge and total revenues received during the

injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period; and

(vi) The related docket numbers in which the interstate pipeline reported storage related injection/withdrawal transportation services.

* * * * *

14. In Part 284, a new Subpart H is added to read as follows:

Subpart H — Assignment of Capacity on Interstate Pipelines

Sec.

284.241 ***Applicability.***

284.242 ***Assignment of firm capacity on upstream pipelines.***

284.243 ***Release of firm capacity on interstate pipelines.***

§ 284.241 ***Applicability.***

This Subpart applies to any interstate pipeline that offers transportation service under Subpart B or G of this part.

§ 284.242 ***Assignment of firm capacity on upstream pipelines.***

An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on upstream

pipelines that offer a transportation service under Subpart B or G of this part. An upstream pipeline is authorized and required to permit a downstream pipeline to assign its firm capacity to the downstream pipeline's firm shippers.

§ 284.243 ***Release of firm capacity on interstate pipelines.***

(a) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must include in its tariff a mechanism for firm shippers to release firm capacity to the pipeline for resale by the pipeline on a firm basis under this section.

(b) Firm shippers must be permitted to release their capacity, in whole or in part, on a permanent or short-term basis, without restriction on the terms or conditions of the release. A firm shipper may arrange for a replacement shipper to obtain its released capacity from the pipeline. A replacement shipper is any shipper that obtains released capacity.

(c) A firm shipper that wants to release any or all of its firm capacity must notify the pipeline of the terms and conditions under which the shipper will release its capacity. The firm shipper must also notify the pipeline of any replacement shipper designated to obtain the released capacity under the terms and conditions specified by the firm shipper.

(d) The pipeline must provide notice of the release, the terms and conditions, and the name of any replacement shipper designated in paragraph (b) of this section, on an electronic bulletin board, for a reasonable period.

(e) The pipeline must allocate released capacity to the person offering the highest rate (not over the maximum rate)

and offering to meet any other terms and conditions of the release. If more than one person offers the highest rate and meets the terms and conditions of the release, the released capacity may be allocated on a basis provided in the pipeline's tariff, provided however, if the replacement shipper designated in paragraph (b) of this section offers the highest rate, the capacity must be allocated to the designated replacement shipper.

(f) Unless otherwise agreed by the pipeline, the contract of the shipper releasing capacity will remain in full force and effect, with the net proceeds from any resale to a replacement shipper credited to the releasing shipper's reservation charge.

(g) To the extent necessary, a firm shipper on an interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part is granted a limited-jurisdiction blanket certificate of public convenience and necessity pursuant to Section 7 of the Natural Gas Act solely for the purpose of releasing firm capacity pursuant to this section.

15. In Part 284, a new Subpart J is added to read as follows:

Subpart J — Blanket Certificates Authorizing Certain Natural Gas Sales by Interstate Pipelines

Sec.

284.281 ***Applicability.***

284.282 ***Definitions.***

284.283 ***Point of unbundling.***

Appendix B

284.284 ***Blanket certificates for unbundled sales services.***

284.285 ***Pregrant of abandonment of unbundled sales services.***

284.286 ***Standards of conduct for unbundled sales service.***

284.287 ***Implementation and effective date.***

284.288 ***Reporting requirements.***

§ 284.281 ***Applicability.***

This subpart applies to any interstate pipeline that offers transportation service under Subpart B or G of this part.

§ 284.282 ***Definitions.***

(a) *Bundled sales service* is gas sales service that is not sold separately from transportation service.

(b) *Sales service* includes firmor interruptible gas sales.

(c) *Unbundled sales service* is gas sales service that is sold separately from transportation service.

§ 284.283 ***Point of unbundling.***

A sales service is unbundled when gas is sold at a point before it enters a mainline system, at an entry point to a mainline system from a production area, or at an intersection with another pipeline system.

Appendix B

§ 284.284 ***Blanket certificates for unbundled sales services.***

(a) *Authorization.* An interstate pipeline that offers transportation service under Subpart B or G of this part is granted a blanket certificate of public convenience and necessity pursuant to Section 7 of the Natural Gas Act authorizing it to provide unbundled firm or interruptible sales in accordance with the provisions of this section.

(b) *Conversion to unbundled firm sales service and firm transportation service.* On the effective date of the pipeline's blanket certificate for unbundled sales services under paragraph (a) of this section, firm sales entitlements under any firm sales service agreement for a bundled sales service are converted to an equivalent amount of unbundled firm sales service and an equivalent amount of unbundled firm transportation service, except as adjusted in §§ 284.14(d) and (e).

(c) *Conversion to unbundled interruptible sales service and interruptible transportation service.* On the effective date of the pipeline's blanket certificate for unbundled sales services under paragraph (a) of this section, interruptible sales volumes under any interruptible sales service agreement for a bundled sales service are converted to an equivalent amount of unbundled sales service and an equivalent amount of unbundled interruptible transportation service.

(d) A pipeline that provides unbundled sales service under this section may serve as an agent of the sales customer to arrange for any pipeline-provided service necessary to deliver gas to the customer.

Appendix B

§ 284.285 ***Pregrant of abandonment of unbundled sales services.***

Abandonment of unbundled sales services is authorized pursuant to Section 7(b) of the Natural Gas Act upon the expiration of the contractual term or upon termination of each individual sales arrangement authorized under § 284.284.

§ 284.286 ***Standards of conduct for unbundled sales service.***

(a) To the maximum extent practicable, the pipeline must organize its unbundled sales and transportation operating employees so that they function independently of each other.

(b) The pipeline must conduct its business to conform to the requirements set forth in § 284.8(b)(2) and § 284.9(b)(2) with respect to the equality of service by not giving shippers of gas sold by the pipeline any preference over shippers of gas sold by any other merchant in matters relating to Part 284 transportation.

(c) The pipeline must comply with § 161.3(a), (b), (d) and (l) of this chapter and comply with § 161.3(c), (e), (f), (g), (h), and (i) of this chapter by considering its unbundled sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate.

(d) The pipeline must comply with § 250.16 of this chapter by considering its unbundled sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate.

(e) A pipeline that provides unbundled sales service under § 284.284 must file tariff provisions and procedures as part of its compliance filing under § 284.14 indicating how the pipeline

is complying with the standards of this section.

§ 284.287 ***Implementation and effective date.***

(a) Except as provided in paragraph (b) of this section, a pipeline that offers transportation under Subpart B or G of this part must file revised tariff sheets to implement the requirements of this Subpart J as part of the compliance filing required under § 284.14.

(b) A pipeline that offers transportation under Subpart B or G of this part that is not authorized to make sales for resale as of the date of its required filing under § 284.14 need not file to implement this Subpart J with its filing under § 284.14, but prior to offering any sales service, such a pipeline must file revised tariff sheets to implement this Subpart J.

(c) A blanket certificate issued under § 284.284 will be effective on the effective date (as approved by the Commission) of the tariff sheets implementing service under that certificate. For a pipeline that is required to file under § 284.14, the tariff sheets implementing service under the blanket certificate will not be effective until after Commission approval of the compliance filings required by § 284.14(b).

§ 284.288 ***Reporting requirements.***

Interstate pipelines engaging in sales under a certificate granted under § 284.284 must file with the Commission by March 1 of each year, an annual report for the preceding calendar year describing for each transaction the identities of the parties, the type of service provided (firm or interruptible), the total volumes sold, and the total revenues received. The report must be signed under oath by a senior official of the company.

Appendix B

Docket No. RM91-11-000

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-065

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued April 8, 1992)

JERRY J. LANGDON, Commissioner, *concurring in part and dissenting in part:*

This Order represents a watershed for the natural gas industry. It marks a turning point for parties to permanently leave outmoded and failed governmental policies behind to face a largely market-driven regulatory regime. Those who fail to take advantage of this opportunity to craft market-sensitive solutions to their energy needs will undoubtedly be left behind. This Order provides a road map to guide all parties toward a competitive market for natural gas without mandating which route they should choose.

I fully support this Order as a final major move toward realizing the promises first set forth in Order No. 436. In the past few years, the Commission has been criticized for its piecemeal approach to implementing important policy objectives. This piecemeal approach has unnecessarily prolonged the transition of the industry by limiting or obviating competitive choices by individual segments of the industry. By

dealing globally with a number of inter-related issues, the Commission will allow market forces — and not regulators — to begin to drive the natural gas industry.

I only regret that we did not take two more steps to facilitate the process:

- provide an additional mechanism to shorten the transition cost recovery process to allow true market signals to emerge sooner rather than later, and

- devise an alternative cost recovery mechanism for the non-market sensitive Great Plains gas.

As to the former I concur; as to the latter, I dissent as discussed below.

Order No. 636 provides only two mechanisms which act to limit gas supply realignment costs which may result from restructuring negotiations: eligibility and prudence. I take seriously the Order No. 636 process for both mechanisms in light of the billions of dollars that have already been billed to consumers in take-or-pay costs.

The Commission's past record on prudence review has been impotent at best. But, as a result of the full pass-through of transition costs allowed by this rule, the Commission has a new, larger prudence role to play. First, we must ensure that transition costs recovered pursuant to Order No. 636 are closely limited to contract realignments occurring as a direct result of implementing this rule. Second, we must determine that the remaining supply contracts are the product of prudent market-driven transactions.

Appendix B

In discussions leading up to the Final Order, I strongly favored an additional, *optional* mechanism which would have encouraged pipelines to offer 10 percent absorption of gas supply realignment costs in exchange for their customers' forgoing their rights to challenge prudence. I believe this optional approach is reasonable, and moreover, is not precluded by the rule. I expect that the pipelines and parties may well use this mechanism as an alternative to lengthy, costly and uncertain prudence reviews.

As to the Order No. 636 treatment of Great Plains gas, every comma, word, sentence and paragraph of the Order is internally inconsistent. Order No. 636's sweeping changes are driven by the overriding need to make natural gas a competitive commodity. We do this by eliminating cross-subsidies and by billing away costs associated with the old way of doing business. Yet in Great Plains, we are timid. I fail to see how the pass-through of such extraordinary gas costs will ultimately benefit the consumer, or transmit accurate pricing signals.

I understand the public trust responsibility with respect to recoupment of the public investment in Great Plains and I would support a proposal to retire that investment through a surcharge on natural gas transportation. The continued operational feasibility of Great Plains, however, should be a choice consumers should make by their willingness to pay the cost of converting coal to gas.

In all other regards, I enthusiastically support the Order. I expect that it will significantly contribute to improving the health and efficiencies of the natural gas industry to the benefit of the nation's consumers.

Jerry J. Langdon
Commissioner